STATEMENT OF BASIS

For Final Permit Renewal

Suckla Farms #1 Underground Injection Well
SENW, 500 feet (ft) from the south line (FSL) and 2020 ft from the west line (FWL),
Section 10, Township 1 North, Range 67 West
Weld County, Colorado

EPA PERMIT NO. CO10938-02115

COMMERCIAL NON-HAZARDOUS
CLASS I DISPOSAL FACILITY

WELD COUNTY, COLORADO

Wattenberg Disposal, LLC
1675 Broadway, Suite 2800
Denver, Colorado 80202

Dated: December 2014

CONTACT: Linda Bowling
U. S. Environmental Protection Agency
Ground Water Program, 8P-W-UIC
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This STATEMENT OF BASIS gives the derivation of site-specific UIC Permit conditions and reasons for them. Referenced sections and conditions correspond to sections and conditions in the Permit.

EPA UIC permits regulate the injection of fluids into underground injection wells so that the injection does not endanger underground sources of drinking water. EPA UIC permit conditions are based upon the authorities set forth in regulatory provisions at 40 CFR Parts 144 and 146, and address potential impacts to underground sources of drinking water. Under 40 CFR 144.35, issuance of this permit does not convey any property rights of any sort or any exclusive privilege, nor authorize injury to persons or property of invasion of other private rights, or any infringement of other Federal, State or local laws or regulations. Under 40 CFR 144 Subpart D, certain conditions apply to all UIC Permits and may be incorporated either expressly or by reference. General Permit conditions for which the content is mandatory and not subject to site-specific differences (40 CFR Parts 144, 146 and 147) are not discussed in this document.

Upon the Effective Date when issued, the Permit authorizes the construction and operation of injection wells so that the injection does not endanger underground sources of drinking water, governed by the conditions specified in the Permit. The Permit is issued for ten (10) years or unless terminated for reasonable cause under 40 CFR 144.39, 144.40 and 144.41.

The Final Permit contains the following changes which were not discussed in the Draft Permit.

- Grammatical edits have been made to create a more comprehensive document;
- The grammatical error in paragraph Part II.D.5.a, which requires the analysis for the constituents in Appendix J has been removed;
- Appendix J – Groundwater Monitoring Parameter List has been modified to eliminate the requirement to perform characteristic analysis identified in 40 Code of Federal Regulations Sections 261.21 thru 261.24. The characteristic analytical requirements continue to be incorporated in the applicable paragraphs Part II.D.5.b.ii and Part II. E.1 of the application;
- A numerical value of 2.5 or greater magnitude has been incorporated into the requirements for reporting and shutting down operations under the requirements for Seismicity, paragraph Part II.E.6;
- Appendix C - Plugging and Abandonment Plan has been altered to comply with the requirements in EPA's Groundwater Program Guidance No. 40: Plugging and Abandonment Requirements for Class II Injection Wells; and
- Appendix H – Alternate Temperature Survey Test with Supplemental Radioactive Tracer Survey Procedure has been modified to incorporate steps to analyze and calculate the percent of fluids which exit the perforations.

PART I. General Information and Description of Facility

Wattenberg Disposal, LLC
1675 Broadway, Suite 2800
Denver, Colorado 80202

on

September 17, 2012

submitted an application for an Underground Injection Control (UIC) Program Permit or Permit Renewal for the following injection well or wells:

Suckla Farms #1 Underground Injection Well
SENW, 500 feet (ft) from the south line (FSL) and 2020 ft from the west line (FWL),
Section 10, Township 1 North, Range 67 West
Weld County, Colorado

The application, including the required information and data necessary to issue or modify a UIC Permit in accordance with 40 CFR Parts 144, 146 and 147, was reviewed and determined by EPA to be administratively complete.

This permit is issued for **ten (10) years**, unless terminated. The permit will be reviewed at least every five years to determine whether action under 40 CFR Section 144.36(a) is warranted. It is the Permittee's responsibility to read and understand all provisions of this permit. The permit will **expire at midnight ten (10) years after the effective date of this permit**, or upon delegation of primary enforcement responsibility for the UIC 1422 Program to the State of Colorado, unless that State has adequate authority and chooses to adopt and enforce this permit as a State permit.

EPA has received an application from Wattenberg Disposal, LLC to renew the permit for an underground injection control (UIC) Class I non-hazardous Permit for the existing Suckla Farms #1 Class I injection well located on private property in Weld County, Colorado. This well was initially permitted as a Class I well on June 16, 1992, for a period of 10 years. A renewal was issued on January 22, 2003. The submittal of a complete application prior to expiration of the Permit extends the existing Permit until completion of the re-permitting process and the issuance of a final decision regarding a new Permit (40 CFR 144.37). The applicant proposes to continue to inject a mixture of fluids produced from oil and gas operations and non-hazardous industrial waste into the Lyons Formation between the depths of 9276 feet and 9418 feet. The initial total dissolved solids (TDS) content of the Lyons Formation was approximately 33,000 mg/liter and an aquifer exemption was not required.

This permit application is for continued operation of a Class I non-hazardous well for the disposal of both produced water from oil and gas operations, including gas plants and methane storage operations, and non-hazardous industrial fluids. The industrial fluids will consist of reclaimed water associated with the removal of underground fuel storage tanks, pit water from oil field wash pits, *contaminated surface water from construction sites, and other non-hazardous fluids. Fluids are anticipated to be from the Front Range area as far south as Pueblo, Colorado. The average injection pressure is anticipated to be 900 pounds per square inch gauge (psig) with an average injection rate of around 1700 barrels of water per day (BWPD). The maximum injection pressure will be limited to 3700 psig.*

The top of the injection zone, the Lyons Formation, is located at a depth of about 9274 feet (ft) KB and extends to 9422 ft KB. The perforated interval extends from 9276 ft to 9418 ft. The Lyons is a massive crossbedded sandstone with fine to coarse grains.

The Suckla Farms injection well is located in a portion of the Spindle Field adjacent to the Weld County Road 19.

TABLE 1.1 shows the status of the well or wells as "New", "Existing", or "Conversion" and for Existing shows the original date of injection operation. Well authorization "by rule" under 40 CFR Part 144 Subpart C expires automatically on the Effective Date of an issued UIC Permit.

TABLE 1.1

WELL STATUS / DATE OF OPERATION

Well Name	Well Status	Date of
Suckla Farms #1	Existing	07/12/1989

The Suckla Farms #1 well was first completed on July 12, 1989. The Suckla Farms #1 injection well was originally issued a permit for the purpose of disposal on July 21, 1992. A renewal final permit was issued on January 22, 2003. This is a permit to issue a second renewal to continue injection activities.

PART II. Permit Considerations (40 CFR 146.24)

Geologic Setting (TABLE 2.1)

TABLE 2.1
GEOLOGIC SETTING
SUCKLA FARMS INJECTION WELL #1

FORMATION NAME	GEOLOGICAL DESCRIPTION	TOP DEPTH, ft	BOTTOM DEPTH, ft	TDS mg/l	ZONE TYPE
Arapahoe	Sandstone,siltstone, and shale	350		< 10,000 mg/l	USDW
Laramie	Sandstone, mudstone, clay and coal	unknown		< 10,000 mg/l	USDW
Fox Hills	Sandstone, siltstone	650		< 10,000	USDW

	and shale			mg/l	
Pierre Shale	Shale	700			Major confining zone
Niobrara Shale	Shale	7362			Confining zone
Codell	Silty, shaley and fine-grained sandstone	7694		unknown	Geological Setting
J Sand	Sandstone, Siltstones and shale	8133		unknown	Geological Setting
Dakota Sandstone	Sandstone and shale	8281		unknown	Geological Setting
Lakota Sandstone	Sandstone	8368		unknown	Geological Setting
Morrison	Mudstone, sandstone, siltstone, and limestone	8404			Confining zone
Entrada	Sandstone	8562		unknown	Geological Setting
Harriman Shale (Forell)	Shale	9069	9139		Confining zone
Blaine Salt	Anhydrite and Shale	9143	9274		Confining Zone
Lyons Sandstone	Sandstone	9274	9422	33,000 mg/l	Injection zone
Santanka Shale	Shale	9422			Confining zone

The Suckla Farms #1 Class I disposal well is located about 25 miles North of Denver, Colorado in the Denver-Julesburg Basin. The Denver-Julesburg Basin is a north-south trending "trough" or asymmetrical Syncline. Strata which are exposed along the Front Range dip steeply eastward. On the east flank of the Basin, the strata dip gently westward. The well is located approximately 5 to 10 miles east of the axis of the Basin where the thickness of the sedimentary section is near its maximum. Formation top depths listed above were obtained from the Well Completion Report for the Suckla Farms #1 well dated July 13, 1989 and page 4 of the permit application. Additional geological data was obtained from the permittee regarding the depths of the Blaine Salt and Lyons Sandstone formations. The designation of USDWs and non-USDWs data has been obtained from page 4 of the application and from the 2003 Statement of Basis for the Final Renewal Permit issued for the Suckla Farms #1 well.

Proposed Injection Zone(s) (TABLE 2.2)

An injection zone is a geological formation, group of formations, or part of a formation that receives fluids through a well. The proposed injection zones are listed in TABLE 2.2.

Injection will occur into an injection zone that is separated from USDWs by a confining zone which is free of known open faults or fractures within the Area of Review.

TABLE 2.2
INJECTION ZONES
SUCKLA FARMS INJECTION WELL #1

Formation Name	**Top (ft)**	**Base (ft)**	**TDS (mg/l)**	**Fracture Gradient (psi/ft)**	**Porosity**	**Exempted?***
Lyons Sandstone	9274	9422	33,000	0.8415	0.06	N/A

C - Currently Exempted
E - Previously Exempted
P - Proposed

The targeted portion of the Lyon injection zone is the sandstone unit encountered at about 9276 ft. The Lyons Sandstone is a massive cross bedded sandstone with fine to coarse grains with some cementing. The perforated interval of the Lyons is from 9276 ft to 9418 ft. The injection zone is expanded to depths between 9274 ft to 9422 ft. to accommodate depths within the Lyons Sandstone that are perforated and sandstones which may store fluid. The depths were determined by the permittee.

As indicated above, the disposal of oil field related fluids and non-hazardous fluids will be into the Lyons Sandstone. The Suckla Farms #1 was sampled and analyzed prior to conversion to a Class I injection well and reservoir fluid contained about 33,000 mg/liter total dissolved solids (TDS).

Confining Zone(s) (TABLE 2.3)
A confining zone is a geological formation, part of a formation, or a group of formations that limits fluid movement above the injection zone. The confining zone or zones are listed in TABLE 2.3

TABLE 2.3
CONFINING ZONES

FORMATION NAME	**GEOLOGICAL DESCRIPTION**	**TOP DEPTH, ft**	**BOTTOM DEPTH, ft**	**TDS, mg/l**	**ZONE TYPE**
Blaine Salt	Anhydrite and shale	9143	9274	N/A	Upper Confining zone
Santanka Shale	Shale	9422		N/A	Lower Confining zone

The upper confining zone is the Blaine Salt and is encountered at 9143 ft. The Santanka Shale serves as the lower confining zone and is encountered at a depth of 9422 ft.

Underground Sources of Drinking Water (USDWs) (TABLE 2.4)
Aquifers or the portions thereof which contain less than 10,000 mg/l total dissolved solids (TDS)

and are being or could in the future be used as a source of drinking water are considered to be USDWs. The USDWs in the area of this facility are identified in TABLE 2.4.

TABLE 2.4
UNDERGROUND SOURCES OF DRINKING WATER (USDW)

FORMATION NAME	GEOLOGICAL DESCRIPTION	TOP DEPTH, ft	BOTTOM DEPTH, ft	TDS mg/l	ZONE TYPE
Arapahoe	Sandstone,siltstone, and shale	350		<10,000 mg/l	USDW
Laramie	Sandstone, mudstone, clay and coal			<10,000 mg/l	USDW
Fox Hills	Sandstone, siltstone and shale	650		<10,000 mg/l	USDW

In this area, the principal aquifers used for public and domestic and other uses are the Arapahoe Formation and the Laramie-Fox Hills aquifer system. These major USDWs overlie the Pierre Shale, which is a major confining unit in the basin, and is approximately 6600 feet thick. The Pierre is principally 6600 feet thick. The Pierre is principally a dark gray marine shale, but sand lenses, such as the Hygiene sand and the Wellington sand do occur in places.

The Hygiene and the Wellington sands often contain water with a quality and quantity sufficient to be defined as a USDW. All the formations underlying the Pierre are not USDWs because they contain water with a TDS of greater than 10,000 mg/liter. The injected interval, prior to injection, contained water with a TDS of approximately 33,000 mg/liter.

PART III. Well Construction (40 CFR 146.22)

TABLE 3.1
WELL CONSTRUCTION REQUIREMENTS
SUCKLA FARMS INJECTION WELL #1

Casing Type	Hole Size (in)	Casing Size (in)	Cased Interval (ft)	Cemented Interval (ft)
Surface	12 ¼	8 5/8	0 – 759	0 – 759
Longstring	5 ½	7 7/8	0 – 9557	8406 - 9557

The approved well completion plan will be incorporated into the Permit as APPENDIX A and will be binding on the Permittee. Modification of the approved plan is allowed under 40 CFR 144.52(a)(1) provided written approval is obtained from the Director prior to actual modification.

Casing and Cementing (TABLE 3.1)
The well construction plan was evaluated and determined to be in conformance with standard practices and guidelines that ensure well injection does not result in the movement of fluids into USDWs. Well construction details for this "new" injection well is shown in TABLE 3.1.

Remedial cementing may be required if the casing cement is shown to be inadequate by cement bond log or demonstration of Part II (External) mechanical integrity.

The Suckla Farm #1 well is constructed in a manner which incorporates special completion (cementing) requirements identified under 40 CFR Section 147.305. Requirements for all wells. These special requirements are implemented to protect USDWs.

Tubing and Packer
Injection tubing is required to be installed from a packer up to the surface inside the well casing. The packer will be set above the uppermost perforation. The tubing and packer are designed to prevent injection fluid from coming into contact with the outermost casing.

Approximately 9254 ft of 2 7/8 inch tubing is presently set in the well with the packer being located approximately 36 ft above the uppermost perforation, 9276 ft KB. Tubing and packer depths shall be maintained within the identified depths mentioned earlier or within a depth of no more than 100 ft. of the top perforation.

Tubing-Casing Annulus (TCA)
The TCA allows the casing, tubing and packer to be pressure-tested periodically for mechanical integrity, and will allow for detection of leaks. The TCA will be filled with fresh water treated with a corrosion inhibitor or other fluid approved by the Director.

The annulus pressure shall be maintained at a positive pressure between one hundred (100) and two hundred (200) psi gauge as measured at the wellhead.

If this pressure cannot be maintained between 100 psig and 200 psig, the Permittee shall follow the procedures listed in Ground Water Guidance No. 35 "Procedures to follow when excessive annular pressure is observed on a well." The annulus pressure is determined to be appropriate because the temperature difference between the injection fluid and the temperature formation causes the temperature in the annulus to rise above the normal 0 psig required value.

Monitoring Devices
The permittee will be required to install and maintain wellhead equipment that allows for monitoring pressures and providing access for sampling the injected fluid. Required equipment may include but is not limited to: 1) shut-off valves located at the wellhead on the injection tubing and on the TCA; 2) a flow meter that measures the cumulative volume of injected fluid; 3) fittings or pressure gauges attached to the injection tubing and the TCA for monitoring the injection and TCA pressure; and 4) a tap on the injection line, isolated by shut-off valves, for sampling the injected fluid.
All sampling and measurement taken for monitoring must be representative of the monitored activity.

The applicant shall be required to monitor the maximum injection pressure and record results in accordance with the conditions of the permit's appendix D. An inspector will perform visual inspections of the well, pressure levels, ground surface, and well head.

The monitoring devices shall continuously monitor: (1) injection pressure; (2) casing head pressure of the tubing/casing annular space; and (3) flow rate and volume. The tubing/casing annulus is to be filled with fluid and maintained between a positive pressure of 100 - 200 psig. This may be achieved through the use of an above-ground fluid reservoir with a gas cap of nitrogen to maintain the positive pressure. A continuous recording of injection volume can be accomplished by use of a cumulative volume totalizer.

The permittee shall provide and maintain in good operating condition: a ½ inch fitting with a cut-off valve at the wellhead on the tubing, and a similar fitting and cut-off valve for the casing/tubing annulus. These valves shall be positioned to allow the attachment of pressure gauges certified for ninety-five (95) percent accuracy, or better, throughout the range of permitted operation, in order to monitor the injection and annulus fluid pressures. A flow meter shall be installed near the wellhead to measure cumulative volumes of injected fluid. These gauges will serve as a check against the readings recorded by the continuous monitoring devices. EPA is further requiring that a sampling tap exist on the line to the disposal well.

PART IV. Area of Review, Corrective Action Plan (40 CFR 144.55)

According to the information provided, there are no wells within the 1/4 mile area of review which penetrates the Lyons Formation.

TABLE 4.1
AOR AND CORRECTIVE ACTION

Well Name/Permit No. Required (Y/N)	Type	Status (Abandoned Y/N)	Total	TOC Depth (ft)	CAP Depth (ft)
49627-MH	Monitoring	No	30	unknown	No
45567	Domestic/Stock	No	450	unknown	No
90356-VE	Domestic	No	740	unknown	No
39799-MH	Monitoring	No	25	unknown	No
47236-MH	Monitoring	No	25	unknown	No
49186-MH	Monitoring	No	15	unknown	No

TABLE 4.1 lists the wells in the Area of Review ("AOR") and shows the well type, operating status, depth, top of casing cement ("TOC") and whether a Corrective Action Plan ("CAP") is required for the well.

The applicant identified ninety-six (96) oil and gas wells which are located within a one (1) mile radius of the Suckla Farms #1 well. These oil and gas wells range in total depth from 4810 ft to 8700 ft. None of the oil and gas wells penetrate the upper confining zones nor do they penetrate the injection zone.

There are fifty-four (54) water wells that are located within a one mile radius of the Suckla Farms #1 well. These water wells extend from a depth of 10 ft to 788 ft. None of the water wells penetrate the upper confining zones or the injection zone. There are several hundreds of feet of confinement (tight geology) which exists between the lowermost water well and the injection zone.

Area of Review

Applicants for Class I, II (other than "existing" wells) or III injection well Permits are required to identify the location of all known wells within the injection well's Area of Review (AOR) which penetrate the injection zone, or in the case of Class II wells operating over the fracture pressure of the formation, all known wells within the area of review that penetrate formations which may be affected by increased pressure. Under 40 CFR 146.6 the AOR may be a fixed radius of not less than one quarter (1/4) mile or a calculated zone of endangering influence.

Corrective Action Plan

For wells in the AOR which are improperly sealed, completed, or abandoned, the applicant shall develop a Corrective Action Plan (CAP) consisting of the steps or modifications that are necessary to prevent movement of fluid into USDWs.

The CAP will be incorporated into the Permit as APPENDIX F and become binding on the permittee.

No corrective action activities were identified for this action.

P ART V. Well Operation Requirements (40 CFR 146.23)

TABLE 5.1
INJECTION ZONE PRESSURES

Formation Name	Depth Used to Calculate	Fracture Gradient (psi/ft)	Specific Gravity	MAIP (psig)
Lyons Formation	9276 ft	0.8415	1.022	3700

An MAIP of 3700 psig was the highest value observed during a 1993 step rate test with no breaking point (formation fracking pressure) observed. Therefore, no formation breakdown of the Lyons injection zone occurred up to the termination of the test at a surface injection pressure of 3700 psig and at an injection rate of 8.0 barrels of water per minute.

Approved Injection Fluid

The approved injection fluid is limited to produced oil field waters, as authorized under the provisions of the previously issued Class II permit, plus nonhazardous industrial waste fluids, as provided for in this Class I permit.

The injectate has the following characteristics:

SUSSEX FORMATION SOURCE WATER	*SPECIFIC GRAVITY*	*TDS, mg/l*
Spindle Field produced water	*1.02*	*13,800*
produced water	*1.017*	*11,065*
Suckla Brown Unit	*1.022*	*12,860*

Injection Pressure Limitation

Injection pressure, measured at the wellhead, shall not exceed a maximum calculated to assure that the pressure used during injection does not initiate new fractures or propagate existing fractures in the confining zones adjacent to the USDWs.

The applicant submitted injection fluid density and injection zone data which was used to calculate a formation fracture pressure and to determine the maximum allowable injection pressure (MAIP), as measured at the surface, for this Permit.

TABLE 5.1 lists the fracture gradient for the injection zone and the approved MAIP, determined according to the following formula:

$$FP = [fg - (0.433 * sg)] * d$$

FP = formation fracture pressure (measured at surface)
fg = fracture gradient (from submitted data or tests)
sg = specific gravity (of injected fluid)
d = depth to top of injection zone (or top perforation)

- *fg* = 0.8415 psi/ft
- *sg* = 1.022
- *d* = 9276 ft (top perforations in the Lyons Sandstone injection zone)
- *FP = 3700 psig*

A Step Rate Test was performed on July 9, 1993. This test was performed on the Lyons injection interval between the depths of 9,276 ft – 9,418 ft in the Suckla Farms #1 well. The operator will need to perform additional tests, including a new Step Rate Test should they request the installation of new perforations or to request an increase in pressure (MAIP). Using the calculation above, the fracture pressure was determined to be 3700 psig.

Injection Volume Limitation
Cumulative injected fluid volume limits are set to assure that injected fluids remain within the boundary of the exempted area. Cumulative injected fluid volume is limited when injection occurs into an aquifer that has been exempted from protection as a USDW.

The injection volume is recorded in Appendix E of the Permit. Cumulative injection volume of oil field water, plus nonhazardous waste fluid will be limited to 8,300,000 barrels over the life of the well unless EPA decides to extend the limits of the injection zone or to terminate the permit. This volume was calculated using the formula shown below, which indicates the amount of fluid required to fill up the portion of the reservoir within a ¼ mile radius around the injection well.

$V = (\pi r^2 hn)/5.615$ *where*
$\pi = 3.14159265$
$r = 1320$ *ft or ¼ mile = radial distance*
$h = 142$ *ft = height of injection zone available for fill up (ft)*
$n = 0.06$ *= porosity of injection zone (decimal percent)*
5.615 *= conversion factor (barrels and* ft^3*)*
$V = 8{,}300{,}000$ *barrels = maximum cumulative volume (bbl)*

Mechanical Integrity (40 CFR 146.8)
An injection well has mechanical integrity if:

1. there is no significant leak in the casing, tubing, or packer (Part I); and
2. there is no significant fluid movement into a USDW through vertical channels adjacent to the injection well bore (Part II).

The Permit prohibits injection into a well which lacks mechanical integrity.

The Permit requires that the well demonstrate mechanical integrity prior to injection and periodically thereafter. A demonstration of mechanical integrity includes both internal (Part I) and external (Part II). The methods and frequency for demonstrating Part I and Part II mechanical integrity are dependent upon well-specific conditions as explained below.

The applicant is required to perform a Part I and Part II MIT as follows:

- *Part I, Shall be performed* ***at least every five (5) years*** *after the last successful demonstration of Mechanical Integrity.*

- *Part II, Shall be performed* ***at least every five (5) years*** *after the last successful demonstration of Mechanical Integrity. Federal regulation 40 CFR 146.8(c)1 requires the absence of significant fluid be determined with either a temperature or noise log. Therefore, a temperature log with a supplemental radioactive tracer survey may be used to perform Part II (External) Mechanical Integrity Testing.*

  The applicant shall perform tests as follows:
  - *With a Temperature Logs or a noise log or*
  - *With a Temperature Log and supplemental Radioactive Tracer Survey (see Appendix H of the Permit for Test Procedures.*

- *Pressure Fall Off Tests with pore pressure data shall be performed annually following the last successful Pressure Fall Off Test as approved/accepted by the EPA Region 8 office.*

PART VI. Monitoring, Recordkeeping and Reporting Requirements

Injection Well Monitoring Program
At least once a year the permittee must analyze a sample of the injected fluid for total dissolved solids (TDS), specific conductivity, pH, and specific gravity. This analysis shall be reported to EPA quarterly as part of the Quarterly Report to the Director. Any time a new source of injected fluid is added, a fluid analysis shall be made of the new source.

Instantaneous injection pressure, injection flow rate, cumulative fluid volume and TCA pressures must be observed on a weekly basis. A recording, at least once every thirty (30) days, must be made of the injection pressure, injection flow rate and cumulative fluid volume, and the maximum and average value for each must be determined for each month. This information is required to be reported quarterly as part of the Quarterly Report to the Director.

All industrial waste fluids delivered to the facility will be sampled for fluid analysis prior to delivery, or prior to being transferred to an on-site 500 barrel storage tanks. These fluid samples shall be analyzed for chemical, physical, radiological, and biological constituents, including pH and conductivity. If the analyses of several loads from the same source indicate little or no change, the Director may elect to waive the requirement that each load be sampled. However, one load of industrial waste coming from the same source (where the process is not likely to change) must be tested each month prior to being transferred to on-site tanks.

A flow meter will measure the quantity of fluids pumped from the storage tanks to the injection system. The commingled fluids will be sampled for analysis at random, but not less than once every three months. This final analysis shall include a determination of total dissolved solids, pH, specific gravity, specific conductivity, major cations and anions, oil and grease, and total organic carbon.

The permittee requires that the average, maximum, and minimum monthly values of injection pressure, flow rate and volume, and annular pressure be reported quarterly, along with the data from fluid analyses. In addition to routine quarterly reporting, the permittee is required to report the results of any mechanical integrity test, well workover, logging, or testing of the well or injection zone. These reports are due within sixty (60) days of the completion of the activity, or at the time of the next scheduled quarterly report, whichever is sooner.

Seismicity data has been included to ensure that EPA is informed of any seismic occurrences in the area. Pore pressure data will be collected to determine if pressure has risen in the proposed location. This information will be used to determine what next steps may be required as a result of recent seismic activities.

PART VII. Plugging and Abandonment Requirements (40 CFR 146.10)

Plugging and Abandonment Plan
Prior to abandonment, the well shall be plugged in a manner that isolates the injection zone and prevents movement of fluid into or between USDWs, and in accordance with any applicable Federal, State or local law or regulation. Tubing, packer and other downhole apparatus shall be removed. Cement with additives such as accelerators and retarders that control or enhance cement properties may be used for plugs; however, volume-extending additives and gel cements

are not approved for plug use. Plug placement shall be verified by tagging. Plugging gel of at least 9.6 lb/gal shall be placed between all plugs. A surface plug shall be set inside and outside of the surface casing to seal pathways for fluid migration into the subsurface. Within sixty (60) days after plugging the owner or operator shall submit Plugging Record (EPA Form 7520 13) to the Director. The Plugging Record must be certified as accurate and complete by the person responsible for the plugging operation. The plugging and abandonment plan is described in Appendix C of the Permit.

PART VIII. Financial Responsibility (40 CFR 144.52)

Demonstration of Financial Responsibility

The permittee is required to maintain financial responsibility and resources to close, plug, and abandon the underground injection operation in a manner prescribed by the Director. The permittee shall show evidence of such financial responsibility to the Director by the submission of a surety bond, or other adequate assurance such as financial statements or other materials acceptable to the Director. The Regional Administrator may, on a periodic basis, require the holder of a lifetime permit to submit a revised estimate of the resources needed to plug and abandon the well to reflect inflation of such costs, and a revised demonstration of financial responsibility if necessary. Initially, the operator has chosen to demonstrate financial responsibility with:

A demonstration of Financial Responsibility in the amount of $84,852 has been provided.

The Director may revise the amount required, and may require the permittee to obtain and provide updated estimates of costs for plugging the well according to the approved Plugging and Abandonment Plan.

Evidence of continuing financial responsibility is required to be submitted to the Director annually.

PART IX. Considerations Under Federal Law (40 CFR § 144.4)

EPA has determined that issuance of Permit Number CO10938-02115 for the Suckla Farms Injection Well #1 is in compliance with the laws, regulations, and orders described at 40 C.F.R. § 144.4, including the National Historic Preservation Act (NHPA) and the Endangered Species Act (ESA).

UNITED STATES ENVIRONMENTAL PROTECTION AGENCY
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UNDERGROUND INJECTION CONTROL (UIC)

FINAL PERMIT RENEWAL

Date Prepared: December 2014

CLASS I
NON-HAZARDOUS INDUSTRIAL WASTE DISPOSAL WELL

UIC Permit Number CO10938-02115

Suckla Farms #1

County & State: Weld County, Colorado

Issued To:

Wattenberg Disposal, LLC
1675 Broadway, Suite 2800
Denver, Colorado 80202

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PART I. AUTHORIZATION TO INJECT

Pursuant to the Underground Injection Control (UIC) Regulations of the U.S. Environmental Protection Agency codified at Title 40 of the Code of Federal Regulations, Parts 124, 144, 146, and 147

Wattenberg Disposal, LLC
1675 Broadway, Suite 2800
Denver, Colorado 80202

hereby referred to as the "Permittee", is authorized to continue to operate a Class I injection well, Suckla Farms #1 Injection Well located in the SENW, 500 feet (ft) from the south line (FSL) and 2020 ft from the west line (FWL), Section 10, Township 1 North, Range 67 West, Weld County, Colorado. Injection shall be for the purpose of disposing of industrial waste fluids and produced water from oil and gas fields and gas plants into the gross intervals of the Lyons Sandstone Formation, 9274 ft – 9422 ft KB, in accordance with conditions set forth herein.

The Environmental Protection Agency (EPA) Underground Injection Control (UIC) program regulates the injection of fluids into injection wells so that injection does not endanger underground sources of drinking water (USDWs). EPA UIC Permit conditions are based on authorities set forth at 40 CFR Parts 144 and 146, and address potential impacts to USDWs.

Under 40 CFR Part 144, Subpart D, certain conditions apply to all UIC Permits and may be incorporated either expressly or by reference. General permit conditions for which the content is mandatory and not subject to site specific differences are not discussed in this document. Issuance of this Permit does not convey any property rights of any sort or any exclusive privilege, nor does it authorize injury to persons or property or invasion of other private rights, or any infringement of other Federal, State, or local laws or regulations (40 CFR 144.35).

All conditions set forth herein refer to Title 40 Parts 124, 144, 146, and 147 of the Code of Federal Regulations and are regulations that are in effect on the date that this permit becomes effective.

A Final Permit for the Suckla Farms #1 injection well originally became effective on July 21, 1992 and previously renewed on January 22, 2003. This permit is issued for **ten (10) years,** unless terminated. It is the Permittee's responsibility to read and understand all provisions of this permit. The permit will **expire at midnight ten (10) years after the effective date of this permit**, or upon delegation of primary enforcement responsibility for the UIC 1422 Program to the State of Colorado, unless that State has adequate authority and chooses to adopt and enforce this permit as a State permit.

Issue Date: DEC 1 2014 Effective Date: DEC 1 2014

Callie A. Videtich
Acting Assistant Regional Administrator
Office of Partnerships and Regulatory Assistance

PART II. SPECIFIC PERMIT CONDITIONS

A. WELL CONSTRUCTION REQUIREMENTS

1. Casing and Cementing.
The well shall be cased and cemented to prevent the movement of fluids into or between underground sources of drinking water. The well casing and cement shall be designed for the life expectancy of the well and of the grade and size shown in APPENDIX A. Remedial cementing may be required if shown to be inadequate by cement bond log or other attempted demonstration of Part II (External) mechanical integrity. The construction procedure submitted with the renewal application is hereby incorporated into this permit as APPENDIX A, and shall be binding on the Permittee.

2. Tubing and Packer Specifications.
Injection tubing is required, and shall be run and set with a packer at or below the depth indicated in APPENDIX A. The packer setting depth may be changed provided it remains below the depth indicated in APPENDIX A and the permittee provides notice and obtains the Director's approval for the change. The applicant submitted details on the tubing and packer in the application; these are incorporated into the permit as APPENDIX A, and shall be binding on the Permittee.

   Injection between the outermost casing protecting an underground source of drinking water (e.g. surface casing, production casing, and liner) and the wellbore is prohibited. Injection directly through the casing (i.e. without tubing) is also prohibited.

3. Sampling and Monitoring Devices.
The Permittee shall install and maintain in good operating condition:

   a) a "tap" at a conveniently accessible location on the injection flow line between the pump house or storage tanks and the injection well, isolated by shut-off valves, for collection of representative samples of the injected fluid for chemical analysis;

   b) one-half (1/2) inch female iron pipe fitting, isolated by shut-off valves and located at the wellhead at a conveniently accessible location, for the attachment of a pressure gauge capable of monitoring pressures ranging from normal operating pressures up to the Maximum Allowable Injection Pressure (MAIP) specified in APPENDIX E:

      (i) on the injection tubing;

      (ii) on the tubing-casing annulus (TCA);

c) a pressure actuated shut-off device attached to the injection flow line set to shut-off the injection pump when or before the Maximum Allowable Injection Pressure specified in APPENDIX E is reached at the wellhead;

d) a non-resettable cumulative volume recorder attached to the injection line;

e) a continuous recording device(s) to monitor injection pressure, flow rate, volume, and the pressure on the annulus between the tubing and the long string of casing. A continuous pressure monitoring device shall be connected to either a continuous chart recorder with a resolution of at least 5 psi or a digital recording system with a sampling frequency of at least every 30 seconds; and

f) flow meters (magnetic or turbine) and continuous recording devices, such as a chart recorder with an accuracy of 1 barrel per minute or a digital recording system with a sampling frequency of at least every 30 seconds shall be installed in the injection line immediately upstream of the wellhead to track and document disposal fluid flow rates, and total fluid volumes.

For a given injection rate, the injection pressure should remain relatively constant. Input flow volumes shall be cross checked against injection pressure records to identify any possible divergence in the injection pressure for a given flow rate. A drop in injection pressure without a corresponding reduction in input flow rate may indicate a possible casing, packer, or other failure.

4. <u>Well Logging and Testing</u>.
Well logging and testing requirements are found in APPENDIX D. The Permittee shall ensure the log and test requirements are performed within the time frames specified in APPENDIX D. Well logs and tests shall be performed according to current EPA-approved procedures. Well log and test results shall be submitted to the Director **within sixty (60) days** of completion of the logging or testing activity, and shall include a report describing the methods used during logging or testing and an interpretation of the test or log results. The following are additional requirements for some logs:

a) Well logs for drilling and deepening activities shall include a description of deviation checks performed on all holes constructed by first drilling a pilot hole, and then enlarging the pilot hole by reaming or another method. Such checks shall be at sufficiently frequent intervals to assure that vertical avenues for fluid migration in the form of diverging holes are not created during drilling. Deviation checks are not required for existing wells which do not require formation drilling and are being renewed, altered, recompleted, and/or converted.

b) Pressure falloff tests shall be performed annually. The pressure falloff tests shall involve injecting fluids at a constant rate for at least twenty-four (24) hours, or a sufficient period of time (whichever is greater) until the reservoir pressure reaches stability (radial flow conditions, as determined by a field evaluation of the raw data), followed by a shut-in period of sufficient duration to establish a valid observation of a pressure falloff curve.

The Permittee shall develop an updated test plan for conducting the pressure falloff test if changes are required. EPA Region 6 has created a guideline for developing a site specific plan to conduct pressure falloff tests. The final test plan shall be submitted to Region 8 for review and approval, at least, thirty (30) days prior to conducting the annual pressure falloff test, if applicable.

The actual falloff test shall conform to the final falloff test plan approved by EPA. This test shall be considered complete when the pressure curve becomes asymptotic to a horizontal line as the reservoir reaches ambient pressure. The initial pressure buildup shall be performed with both a downhole pressure gauge with an accuracy of 0.01 psi and surface monitoring equipment utilizing pressure monitoring devices with an accuracy of 0.01 psi to establish a correlation between surface and downhole measurements. It is important that the initial and subsequent tests follow the same test procedure, so that valid comparisons of reservoir pressure, permeability, and porosity can be made. At a minimum, subsequent tests shall be conducted with downhole and surface pressure monitoring devices with an accuracy of 0.01 psi. The permittee shall analyze test results and provide a report with an appropriate narrative interpretation of the test results, including an estimate of reservoir parameters, information on any reservoir boundaries, an estimate of the well skin effect, and reservoir flow conditions. The report shall also compare the test results with the previous years test data and shall be prepared by a knowledgeable analyst.

5. Postponement of Construction or Conversion.
The Permittee shall complete (or recomplete) well construction within one year of the Effective Date of the Permit, if applicable. Authorization to construct and operate shall expire if the well has not been constructed or recompleted **within one (1) year** of the Effective Date of the Permit or Authorization and the Permit may be terminated under 40 CFR Section 144.40, unless the Permittee has notified the Director and requested an extension prior to expiration. Notification shall be in writing, and shall state the reasons for the delay and provide an estimated completion date. Once Authorization has expired under this part, the complete permit process including opportunity for public comment may be required before Authorization to construct and operate may be re-issued.

6. Proposed Changes and Workovers.
Workovers and alterations shall meet all conditions of the Permit. Prior to beginning any addition or physical alteration to an injection well that may significantly affect the tubing, packer or casing, the Permittee shall give advance notice to the Director and

obtain the Director's approval. The Permittee shall record all changes to well construction on a Well Rework Record (EPA Form 7520-12), and shall provide this and any other record of well work over, logging, or test data to EPA **within sixty (60) days** of completion of the activity.

B. CORRECTIVE ACTION

The Permittee is not required to take any corrective action for this permit as specified in Appendix F.

C. MECHANICAL INTEGRITY

1. Types of Mechanical Integrity.
The Permittee is required to ensure that each injection well maintains mechanical integrity at all times. Pursuant to 40 CFR Section 146.8, an injection well has mechanical integrity if it has:

Internal (or Part I) Mechanical Integrity (MI):
There is no significant leak in the casing, tubing, or packer. Internal MI generally is demonstrated by pressure testing the well's annulus to identify leaks; and

External (or Part II) MI:
There is no significant fluid movement into an underground source of drinking water (USDW) through vertical channels adjacent to the injection well bore. External MI involves evaluating the integrity of the cement behind the casing to find fluid channels or leaks, which is done using a noise log or temperature logs.

Other UIC regulations which may apply include: 40 CFR Section 146.13.

2. Demonstration of MI.
The Permittee shall demonstrate Internal and External MI initially and periodically thereafter, as described in APPENDIX D. The Permittee shall demonstrate Internal MI after any workover which affects the tubing, packer, or casing. The Director may stipulate specific test methods and criteria best suited for the specific well construction and injection operation. Well-specific conditions present at this well site that dictate the specific method(s) and frequency required for demonstrating MI, are discussed in the Statement of Basis. The method(s) and frequency required, designed to demonstrate both Internal (Part I) and External (Part II) MI, are listed in APPENDIX D of this Permit. The Director, by written notice, may require the Permittee to comply with an alternate schedule describing when MI demonstrations shall be made. The Director may require additional or alternative tests if the results presented by the Permittee are not satisfactory to the Director.

3. Mechanical Integrity Test Methods and Criteria.
EPA-approved methods shall be used to demonstrate MI. The following EPA Region 8 guidance and guidelines may be accessed online at *http://www2.epa.gov/region8/logs-and-tests-documents.html*, or will be provided to you upon request.

- "Pressure Testing Injection Wells for Part I (Internal) Mechanical Integrity", *Ground Water Section Guidance No. 39*
- "Cement Bond Logging Techniques and Interpretation" *Groundwater Section Guidance No. 34*
- "Temperature Logging for Mechanical Integrity," January 12, 1999
- "Radioactive Tracer Surveys for Evaluating Fluid Channeling Behind Casing near Injection Perforations," September 8, 2009

4. Notification Prior to Testing.
The Permittee shall notify the Director **at least thirty (30) days** prior to any scheduled MI test. The Director may allow a shorter notification period if it would be sufficient to enable EPA to witness the test. Notification may be in the form of a yearly or quarterly scheduled mechanical integrity test(s), or it may be on an individual basis.

5. Loss of Mechanical Integrity.
If the well fails to demonstrate MI during a test, or a loss of MI becomes evident during operation (such as presence of pressure in the tubing-casing annulus (TCA), water flowing at the surface, etc), the Permittee shall notify the Director **within twenty-four (24) hours** (see Part III, Section E.11.(c) of this permit) and the well shall be shut-in **within forty-eight (48) hours** unless the Director requires immediate shut-in.

Within five (5) days of a loss of MI, the Permittee shall submit a follow-up written report that documents test results, repairs undertaken or a proposed remedial action plan. Injection operations shall not be resumed until after the well has successfully been repaired and demonstrated MI, and the Director has provided written approval to resume injection.

D. WELL OPERATION

1. Requirements Prior to Commencing Injection.
Injection of Class I non-hazardous materials into the Suckla Farms #1 is presently occurring under the authority of the existing Permit. Upon the effective date of this Permit, continued injection into the Suckla Farms #1 is authorized subject to the conditions herein.

2. Injection Zone.
Injection is permitted only within the approved injection zone listed in APPENDIX

E. Additional individual injection perforations may be added provided that they remain within the approved injection zone and the Permittee provides notice to the Director in accordance with Part II, Section A.6.

3. Injection Pressure Limitation.

a) The permitted Maximum Allowable Injection Pressure (MAIP), measured at the wellhead, is found in APPENDIX E. Injection pressure shall not exceed the amount the Director determines is appropriate to ensure that injection does not initiate new fractures or propagate existing fractures in the injection zone. In no case shall injection pressure cause the movement of injected or formation fluids into a USDW.

b) The pressure limit (MAIP) in paragraph (a) may be increased by the Director if the fracture pressure of the injection formation will not be exceeded, and the Permittee demonstrates that the proposed increase in surface pressure is necessary: (1) to overcome friction losses in the injection system, or (2) to inject the volume rate of fluid set by Part II, Section D.4., below. Either demonstration shall be made by performing a step rate test, using fluid normally injected, to determine both the instantaneous shut-in pressure (ISIP) and the formation breakdown pressure. The Director will determine any allowable increase based on the test results and other parameters reflecting actual injection operations.

c) The Permittee shall give **thirty (30) days** advanced notice to the Director if an increase of injection pressure will be sought. Details of the proposed tests shall be submitted **at least seven (7) days** prior to the tests. Results of all tests shall be submitted to the Director **within sixty (60) days** of the test. Injection at the increased pressure shall be approved by the Director, in writing, before the Permittee may begin continuous operations at the pressure.

d) Any approval by the Director for the increased pressure limitations as stated in paragraph (b) shall be made a part of this permit by minor modification without further opportunity for public comment.

4. Injection Volume and Rate Limitations.
Injection volume is limited to the volume specified in APPENDIX E. This volume is based on the amount of fluid necessary to fill up the portion of the reservoir within a ¼ mile radius around the injection well. The injection rate will not be limited, but in no instance shall the injection pressure exceed that listed in APPENDIX E. When the maximum cumulative is reached, EPA will make a decision whether to extend the limits of the injection zone or to terminate the permit; however, analysis of monitoring records and annual pressure fall-off test data may dictate otherwise at the time of the scheduled five year review.

5. <u>Injection Fluid Limitation</u>.
The Permittee is authorized to inject produced water from oil and gas exploration and production wells, oil and gas related fluids, nonhazardous fluids from underground storage tank (UST) cleanup sites, and other nonhazardous industrial wastes as approved by the Director in APPENDIX G or approved by other written correspondence from the EPA. Fluids are brought to the surface in connection with surface gas storage operations, or conventional oil and gas production and may be commingled with waste waters from gas plants which are an integral part of production operations, unless those waters are classified as a hazardous waste at the time of injection. Injection of any hazardous waste as identified by EPA under 40 CFR 261.3 is prohibited. The Permittee may request new sources of fluids for injection by following the procedures provided below.

a) New additions for source waters (oil and gas exploration and production fluids) and UST (conventional fuel and heating oil) fluid sources shall be made a binding part of this permit following the procedures outlined below, prior to acceptance of the fluid for disposal:

(i) Include the source name, location, Permittee, and a brief description of the operation that produced the waste fluid. If the source is an UST source(s) (conventional fuel and heating oil), the discussion must provide information demonstrating that no metals above the Characteristics of Toxicity are present in the fluid.
(ii) The request shall be accompanied by a water analysis consisting of at least total dissolved solids, pH, specific gravity, and specific conductivity.
(iii) Any approval for injection may be granted verbally, with subsequent written approval from the Director.

b) For new UST (other than conventional fuel and heating) or industrial non-hazardous fluid sources shall be made a binding part of this permit following the procedures outlined below:

(i) Include the source name, location, Permittee, and a brief description of the operation that produced the waste fluid. If the source is an UST site, the discussion must provide information demonstrating that no metals above the TC toxicity characteristics are present in the fluid.
(ii) The request shall include a complete analysis of the fluids, including cations, anions, BTEX, Characteristic of Corrosivity, Characteristic of Toxicity using the Toxicity Characteristic Leaching Procedure (TCLP) for all listed parameters, Characteristic of Ignitability, and Characteristic of Reactivity. See EPA's regulations 40 CFR Sections 261.21 through 261.24 for more information. Also, include an analysis for Total Dissolved Solids, pH, Specific Gravity, and Specific Conductivity, and the constituents in Appendix J.

(iii) Any approval for injection may be granted verbally, with subsequent written approval from the Director.

6. Tubing-Casing Annulus (TCA) Fluids.
Requirements for the Tubing – Casing Annulus are identified in Appendix E. The tubing-casing annulus (TCA) shall be filled with water treated with corrosion inhibitor and oxygen scavenger, or other fluid approved by the Director.

E. MONITORING, RECORDKEEPING, AND REPORTING OF RESULTS

1. Injection Well Monitoring Program.
Samples and measurements shall be representative of the monitored activity. A list of parameters and EPA methods to use in the evaluation of wastewater sources described below is included in APPENDIX J. The permittee shall utilize the applicable analytical methods described in Table 1 of 40 CFR § 136.3, or Appendix III of 40 CFR Part 261, or in certain circumstances, by other methods that have been approved by the EPA Administrator. Monitoring shall consist of:

a) *analysis of all injection fluids and evaluation of any hazards, performed:*

(i) quarterly monitoring for: pH, Total Dissolved Solids (TDS), and specific gravity.

Note: Data for this analysis shall be obtained in accordance with the schedule identified in paragraphs Part II.E.1.(b), (c), and (d) and reported in the quarter that the data is obtained;

(ii) The permittee shall submit a comprehensive water analysis using the parameters in APPENDIX J and provide a brief summary to the Director **within thirty (30) days** of observing any significant change(s) in the parameters measured under Part II, Section E.1.(a).(i) of this permit: pH, TDS, and specific gravity. The permittee shall identify the potential of any observed significant change(s) to cause fractures and/or of the potential of the injected fluid to exhibit a hazardous characteristic in the brief summary. See EPA's regulations 40 CFR Sections 261.21 through 261.24 for more information. A significant change observed for the parameters measured for the injection fluid are:

- ☐ pH - Analysis of the fluid's pH value shows it to be less than 2 and/or greater than 12.5;
- ☐ TDS - Measured TDS values are 20% greater than the parameter's baseline value; and/or
- ☐ Specific Gravity - Specific gravity data is 10% greater than the parameter's baseline value.

The applicant shall use baseline data for the Suckla Farm #1 disposal well. Baseline data shall be based on three years of monitoring events and submitted to the EPA **within ninety (90) days of receipt of a final permit.** Samples and measurements shall be representative of the monitored activity.

b) *For fluids which vary in process and/or composition (these fluids may vary in chemical composition)*, the analysis of industrial waste fluids shall be performed prior to delivery, or prior to being pumped from individual delivery trucks into on-site storage tanks. Fluid samples shall be analyzed for chemical, physical, biological, and radiological constituents, including cations and anions, pH, conductivity and total dissolved solids content. All water samples shall be analyzed for the parameters listed in APPENDIX J.

If however, the analyses of four (4) loads indicates the material is not hazardous and the quality has little variability, the Director may waive the requirement for analyzing every load. Subsequent to this waiver, a minimum of one load in five shall be analyzed for chemical, physical, biological, and radiological constituents, including cations and anions, pH, conductivity and total dissolved solids content. Data analysis shall be performed in accordance with APPENDIX J and Part II, Section E.1.a of this permit.

c) *For fluids associated with a specific process which do not vary in chemical composition*, the analysis of industrial waste fluids received at the well site shall be performed once every ten loads or once per month, whichever is less. Fluid samples shall be analyzed for chemical, physical, biological, and radiological constituents, including cations and anions, pH, conductivity, and total dissolved solids content. If, however, the analyses of the monthly samples show significant variability (variation of greater than 20%) chemical composition and/or pH value shows it to be less than 2 and/or greater than 12.5; the frequency of analysis may be increased to once every two loads or once per month, whichever is less. Data analysis shall be performed in accordance with APPENDIX J and Part II, Section E.1.a of this permit.

d) *Analysis of commingled injection fluids.* Commingled injection fluids are those waters pumped from the various storage tanks to the injection system. An analysis for commingled injection fluids should occur prior to injection and shall be performed at random, but not less than once every three months, for total dissolved solids, pH, specific conductivity, specific gravity, major cations and anions, oil and grease, and total organic carbon. Data analysis shall be performed in accordance with Part II, Section E.1.a of this permit. See APPENDIX J for the list of major cations and anions.

2. <u>Monitoring Information</u>.
Records of any monitored activity required under this permit shall include:

a) Monitoring of fluid sources accepted for disposal
   (i) maintain a record of each source of fluid received for disposal,
   (ii) the name of the source,
   (iii) the well name and API number if applicable,
   (iv) the volume of each load (in barrels), and
   (v) the owner of the facility supplying the wastewater;

b) the date, exact place, and time of sampling or field measurements;

c) the name of the individual(s) who performed the sampling or measurements;

d) the exact sampling method(s) used to take samples;

e) the date(s) laboratory analyses were performed;

f) the name of the individual(s) who performed the analysis;

g) the analytical techniques or methods used by laboratory personnel; and

h) the results of such analyses.

3. <u>Frequency of Monitoring</u>

a) *Continuous monitoring of flow rate and cumulative volume.* If the continuous monitoring is carried out with digital equipment, the instrumentation shall be capable of recording at least one value for each of the parameters at least every thirty (30) seconds. Initially, recordings shall be made once every ten (10) minutes. If the monitoring is recorded with a continuous chart recorder, the chart shall have a scale that will allow a change in rate of 5 barrels per day to be detected. Monitoring must occur whether or not fluids are being injected. This information shall be analyzed in the first annual report under this Permit to determine if this frequency is representative of the injection activity. A minor modification to the Permit shall be made to increase the frequency of recording if the variability of the injection volume and rate (as warranted by the data results) affects the representative nature of the data. A minor modification to the Permit may be made to decrease the frequency of recording if the Director determines that the fluctuation of parameters is such that less frequent data collection would not significantly affect the representative nature of the reported data.

b) *Continuous monitoring of injection and annulus pressure.* Continuous monitoring shall be at the wellhead. If the continuous monitoring is carried out with a continuous chart recorder, the chart shall be of a scale that allows changes in pressure of 5 psi to be detected. If the continuous monitoring is carried out with digital equipment, the instrumentation shall be capable of recording at least one value for each of the parameter at least every thirty (30) seconds. Initially, recordings should be made once every ten (10) minutes. Monitoring must occur whether or not fluids are being injected. Manual reading from a pressure gage on the injection tubing and the annulus shall be taken daily for comparison to the continuous monitoring and recording devices.

The information on pressure shall be analyzed in the first annual report to determine if the continuous monitoring equipment is providing information representative of the injection activity. If digital recording equipment is utilized, the analysis shall include an analysis of the representative nature of the recording frequency. A minor modification to the Permit shall be made to increase the frequency of recording if the variability of the injection pressure and annulus (as warranted by the data results) affects the representative nature of the data. A minor modification to the Permit may be made to decrease the frequency of recording if the Director determines that the fluctuation of the parameters is such that less frequent data collection would not significantly affect the representative nature of the reported data.

c) *Monitoring data shall be recorded as follows:*

(i) **weekly** observations and recordings (including summary graphs) of the injection pressure, flow rate and volume. The monthly average, maximum, and minimum injection pressure, flow rate, and volume values;
(ii) **weekly** preparation of a list of all individual sources of waste fluids brought to the facility (including the facility well name and API number, if applicable) and the total volume from each source shall be provided;
(iii) **weekly** observations and recordings (including summary graphs) of the annulus pressure and annulus fluid level. The monthly average, maximum, and minimum annulus pressure values, as well as the annulus fluid level; and
(iv) **weekly** summary of the results of the monitoring required by Part II, Section E.1.(a), (b), (c), and (d) of this permit.

All data shall be reported quarterly to the Denver EPA office, as per Part II, Section E.5.

4. Recordkeeping.
The Permittee shall retain records concerning: all monitoring information and copies of all reports required by this permit for a period of **at least five (5) years** from the

date of the sample, measurement, or report, during the operating life of the well. Monitoring data will be kept in the local office of the Permittee. This period may be extended anytime prior to its expiration by request of the Director.

5. Reporting of Results.

The Permittee shall submit **Quarterly** Reports to the Director which identifies seismic activities in the area and summarizes the results of the monitoring information required by Part II, Section E.1. of this permit. The Permittee shall also submit results of any mechanical integrity tests (MIT), any well workovers, logging, or testing that reveal conditions of the well or injection zone. These reports are due **within sixty (60) days** of the completion activity or at the time of the next quarterly report, whichever is sooner.

The first Quarterly Report shall cover the period from the effective date of the permit through the end of the quarter period. Subsequent **Quarterly** Reports shall cover the periods of: January 1 through March 31, April 1 through June 30, July 1 through September 30, and October 1 through December 31. Each **Quarterly** Report shall be submitted to the Denver Office by the last day of the following month.

6. Seismicity.

The U.S. Geological Survey (USGS) Earthquake Hazards Program operates an email notification service which reports real-time earthquake events for any area specified by the user. The permittee is required to subscribe to this service, known as the Earthquake Notification Service (ENS). Details for the ENS can be found at:

https://sslearthquake.usgs.gov/ens/

and a subscription can be initiated at:

https://sslearthquake.usgs.gov/ens/register

For any seismic event with a magnitude of 2.5 or greater that is reported within two miles of the permit boundary, the permittee shall immediately cease injection and report to EPA within twenty-four (24) hours according to Part III, Section E.11.c of this permit. Injection shall not resume until the Permittee has obtained approval to recommence injection from EPA.

For any seismic event with a magnitude of 2.5 or greater occurring between two and fifty miles of the permit boundary, that event will be recorded and reported to EPA on a quarterly basis.

F. PLUGGING AND ABANDONMENT

1. Notice of Plugging and Abandonment (P&A).
The Permittee shall notify the Director in writing **at least forty-five (45) days** prior to plugging and abandoning an injection well and converting to a non-injection well.

2. Plugging and Abandonment Plan.
The Permittee shall plug and abandon the well as provided in the approved Plugging and Abandonment Plan. EPA reserves the right to change the manner in which the well will be plugged if the well is modified during its permitted life or if the well is not made consistent with EPA requirements for construction and mechanical integrity. The Director may ask the Permittee to update the estimated plugging cost periodically. Such estimates shall be based upon costs which a third party (such as EPA) would incur to plug the well according to the plan. See the approved Plugging and Abandonment Plan in APPENDIX C of this permit. The Permittee shall submit a revised Plugging and Abandonment Plan which has been corrected to include correct depths once the well has been recompleted. The Permittee may provide three revised cost estimates if the Plugging and Abandonment Plan changes significantly, as well.

3. Cessation of Injection Activity.
After a cessation of injection for **two (2) years**, the Permittee shall plug and abandon the well in accordance with the Plugging and Abandonment Plan unless the Permittee:

   a) provides notice to the Director; and

   b) demonstrates that the well will be used in the future; and

   c) describes actions or procedures, satisfactory to the Director, that will be taken to ensure that the well will not endanger underground sources of drinking water during the period of temporary abandonment.

4. Plugging and Abandonment Report.
Within sixty (60) days after plugging the well, the Permittee shall submit a report on Form 7520-13 to the Director. The report shall be certified as accurate by the person who performed the plugging operation and the report shall consist of either: (1) a statement that the well was plugged in accordance with the plan, or (2) where actual plugging differed from the plan, a statement that specifies the different procedures followed.

G. FINANCIAL RESPONSIBILITY

1. Financial Responsibility.
The Permittee shall maintain continuous compliance with the requirement to maintain

financial responsibility and resources to close, plug, and abandon the underground injection well(s). No substitution of a demonstration of financial responsibility shall become effective until the Permittee receives written notification from the Director that the alternative demonstration of financial responsibility is acceptable. The Director may, on a periodic basis, require the holder of a permit to revise the estimate of the resources needed to plug and abandon the well to reflect changes in such costs and may require the Permittee to provide a revised demonstration of financial responsibility.

2. Insolvency of Financial Institution.
In the event of:

a) the bankruptcy of the trustee or issuing institution of the financial mechanism;

b) suspension or revocation of the authority of the trustee institution to act as trustee; or

c) the institution issuing the financial mechanism losing its authority to issue an instrument.

The Permittee shall notify the Director in writing, **within ten (10) business days**, and the Permittee shall establish other financial assurance or liability coverage acceptable to the Director **within sixty (60) days** after any event specified in (a), (b), or (c) above.

The Permittee shall also notify the Director by certified mail of the commencement of voluntary or involuntary proceedings under Title 11 (Bankruptcy), U.S. Code naming the owner or Permittee as debtor, **within ten (10) business days** after the commencement of the proceeding. A guarantor, if named as debtor of a corporate guarantee, shall make such a notification as required under the terms of the guarantee.

PART III. GENERAL PERMIT CONDITIONS

A. EFFECT OF PERMIT

The Permittee is allowed to engage in underground injection in accordance with the conditions of this permit. The Permittee, as authorized by this permit, shall not construct, operate, maintain, convert, plug, abandon, or conduct any other injection activity in a manner that allows the movement of fluid containing any contaminant into underground sources of drinking water (USDW), if the presence of that contaminant may cause a violation of any primary drinking water regulation under 40 CFR Part 142 or otherwise adversely affect the health of persons. Any underground injection activity not authorized in this permit or otherwise authorized by permit or rule is prohibited. Issuance of this permit does not convey property rights of any sort or any exclusive privilege; nor does it authorize any injury to persons or property, any invasion of other private rights, or any infringement of any other Federal, State or local law or regulations. Compliance with the terms of this permit does not constitute a defense to any enforcement action brought under the provisions of Section 1431 of the Safe Drinking Water Act (SDWA) or any other law governing protection of public health or the environment for any imminent and substantial endangerment to human health or the environment, nor does it serve as a shield to the Permittee's independent obligation to comply with all UIC regulations.

B. PERMIT ACTIONS

1. Modification, Reissuance, or Termination.
The Director may, for cause or upon request from the Permittee, modify, revoke and reissue, or terminate this permit in accordance with 40 CFR Sections 124.5, 144.12, 144.39, and 144.40. Also, the permit is subject to minor modifications for cause as specified in 40 CFR Section 144.41. The filing of a request for a permit modification, revocation and reissuance, or termination or the notification of planned changes or anticipated noncompliance on the part of the Permittee does not stay the applicability or enforceability of any permit condition.

2. Transfers.
This permit is not transferrable to any person except after notice is provided to the Director and the requirements of 40 CFR Section 144.38 is complied with. The Director may require modification, or revocation and reissuance, of the permit to change the name of the Permittee and incorporate such other requirements as may be necessary under the SDWA.

3. Transition From Expiring Permit to Permit Reauthorization.
Adherence to all requirements under 40 CFR Part 144, 146, and 147, including construction, has been verified for this well. An Internal (Part I) Mechanical Integrity

(MI) and External (Part II) MI **is required for reauthorization** of injection activities for this well.

4. Conversions

   The Director may, for cause or upon a written request from the Permittee, allow conversion of the well from a Class I injection well to a non-Class I well. Conversion may not proceed until the Permittee receives written approval from the Director. Conditions of such conversion may include but are not limited to, approval of the proposed well rework, follow up demonstration of mechanical integrity, well-specific monitoring and reporting following the conversion, and demonstration of practical use of the converted configuration.

5. Permittee Change of Address

   Upon the Permittee's change of address, or whenever the Permittee changes the address where monitoring records are kept, the Permittee must provide written notice to the Director within 30 days.

C. SEVERABILITY

The provisions of this permit are severable, and if any provision of this permit or the application of any provision of this permit to any circumstance, is held invalid, the application of such provision to other circumstances, and the remainder of this permit shall not be affected thereby.

D. CONFIDENTIALITY

In accordance with 40 CFR Part 2 and 40 CFR Section 144.5, any information submitted to EPA pursuant to this permit may be claimed as confidential by the applicant. Any such claim shall be asserted at the time of submission by stamping the words "confidential business information" on each page containing such information. If no claim is made at the time of submission, EPA may make the information available to the public without further notice. If a claim is asserted, the validity of the claim will be assessed in accordance with the procedures in 40 CFR Part 2 (Public Information). Claims of confidentiality for the following information will be denied:

- The name and address of the Permittee, and
- Information which deals with the existence, absence, or level of contaminants in drinking water.

E. GENERAL DUTIES AND REQUIREMENTS

1. Duty to Comply.
The Permittee shall comply with all conditions of this permit, except to the extent and for the duration such noncompliance is authorized by an emergency permit. Any permit noncompliance constitutes a violation of the SDWA and is grounds for enforcement action, permit termination, revocation and re-issuance, or modification. Such noncompliance may also be grounds for enforcement action under the Resource Conservation and Recovery Act (RCRA).

2. Penalties for Violations of Permit Conditions.
Any person who violates a permit requirement is subject to civil penalties, fines, and other enforcement action under the SDWA and may be subject to such actions pursuant to the RCRA. Any person who willfully violates permit conditions may be subject to criminal prosecution.

3. Continuation of Expiring Permits.

a) Duty to Reapply. If the Permittee wishes to continue an activity regulated by this permit after the expiration date of this permit, the Permittee shall submit a complete application for a new permit at least one hundred eighty (180) days before this permit expires.

b) Permit Extensions. The conditions of an expired permit may continue in force in accordance with 5 U.S.C. 558I until the effective date of a new permit, if:

(i) The Permittee has submitted a timely application which is a complete application for a new permit; and

(ii) The Director, through no fault of the Permittee, does not issue a new permit with an effective date on or before the expiration date of the previous permit.

c) Enforcement. When the Permittee is not in compliance with the conditions of the expiring or expired permit the Director may choose to do any or all of the following:

(i) Initiate enforcement action based upon the permit which has been continued;

(ii) Issue a notice of intent to deny the new permit. If the permit is denied, the owner or Permittee would then be required to cease the activities authorized by the continued permit or be subject to enforcement action for operating without a permit;

(iii) Issue a new permit under Part 124 with appropriate conditions; or

(iv) Take other actions authorized by these regulations.

d) State Continuation. An EPA issued permit does not continue in force beyond its expiration date under Federal law if at that time a State has primary enforcement authority. A State authorized to administer the UIC program may continue either EPA or State-issued permits until the effective date of the new permits, if State law allows. Otherwise, the facility or activity is operating without a permit from the time of expiration of the old permit to the effective date of the State-issued new permit.

4. Need to Halt or Reduce Activity not a Defense.
It shall not be a defense for a Permittee in an enforcement action that it would have been necessary to halt or reduce the permitted activity in order to maintain compliance with the conditions of this permit.

5. Duty to Mitigate.
The Permittee shall take all reasonable steps to minimize or correct any adverse impact on the environment resulting from noncompliance with this permit.

6. Proper Operation and Maintenance.
The Permittee shall at all times properly operate and maintain all facilities and systems of treatment and control (and related appurtenances) which are installed or used by the Permittee to achieve compliance with the conditions of this permit. Proper operation and maintenance includes effective performance, adequate funding, adequate Permittee staffing and training, and adequate laboratory and process controls, including appropriate quality assurance procedures. This provision requires the operation of back-up or auxiliary facilities or similar systems only when necessary to achieve compliance with the conditions of this permit.

7. Duty to Provide Information.
The Permittee shall furnish the Director, within a time specified, any information which the Director may request to determine whether cause exists for modifying, revoking and reissuing, or terminating this permit, or to determine compliance with this permit. The Permittee shall also furnish to the Director, upon request, copies of records required to be kept by this permit.

8. Inspection and Entry.
The Permittee shall allow the Director, or an authorized representative, upon the presentation of credentials and other documents as may be required by law to:

a) Enter upon the Permittee's premises where a regulated facility or activity is located or conducted, or where records are kept under the conditions of this permit;

b) Have access to and copy, at reasonable times, any records that shall be kept under the conditions of this permit;

c) Inspect at reasonable times any facilities, equipment (including monitoring and control equipment), practices, or operations regulated or required under this permit; and

d) Sample or monitor, at reasonable times, for the purposes of assuring permit compliance or as otherwise authorized by the SDWA any substances or parameters at any location.

9. Records of the Permit /Issuance Application.
The Permittee shall maintain records of all data required to complete the permit application and any supplemental information submitted for a period of **five (5) years** from the effective date of this permit. This period may be extended by request of the Director at any time.

10. Signatory Requirements.
All reports or other information requested by the Director shall be signed and certified according to 40 CFR Section 144.32.

11. Reporting of Noncompliance.

a) Anticipated Noncompliance. The Permittee shall give advance notice to the Director of any planned changes in the permitted facility or activity which may result in noncompliance with permit requirements.

b) Compliance Schedules. Reports of compliance or noncompliance with, or any progress reports on, interim and final requirements contained in any compliance schedule of this permit shall be submitted **no later than thirty (30) days** following each schedule date.

c) Twenty-four Hour Reporting.

(i) The Permittee shall report to the Director any noncompliance which may endanger health or the environment. Any information shall be provided orally within twenty-four (24) hours from the time the Permittee becomes aware of the circumstances by telephoning EPA at **(303) 312-6211 (during normal business hours)** or at **(303) 293-1788 (for reporting at all other times)**. The following information shall be included as information, which shall be reported orally **within twenty-four (24) hours**:

(A) Any monitoring or other information which indicates that any contaminant may cause endangerment to an underground source of drinking water; and/or

(B) Any noncompliance with a permit condition or malfunction of the injection system which may cause fluid migration into or between underground sources of drinking water.

(ii) A written submission shall also be provided **within five (5) days** of the time the Permittee becomes aware of the circumstances. The written submission shall contain a description of the noncompliance and its cause; the period of noncompliance, including exact dates and times, and if the noncompliance has not been corrected, the anticipated time it is expected to continue; and steps taken or planned to reduce, eliminate, and prevent reoccurrence of the noncompliance.

d) Oil Spill and Chemical Release Reporting. The Permittee shall comply with all reporting requirements related to the occurrence of oil spills and chemical releases by contacting the National Response Center (NRC) at (800) 424-8802, (202) 267-2675, or through the NRC website http://www.nrc.uscg.mil/index.htm.

e) Other Noncompliance. The Permittee shall report all other instances of noncompliance not otherwise reported at the time monitoring reports are submitted. The reports shall contain the information listed in Part III, Section E.11.(c)(ii) of this permit.

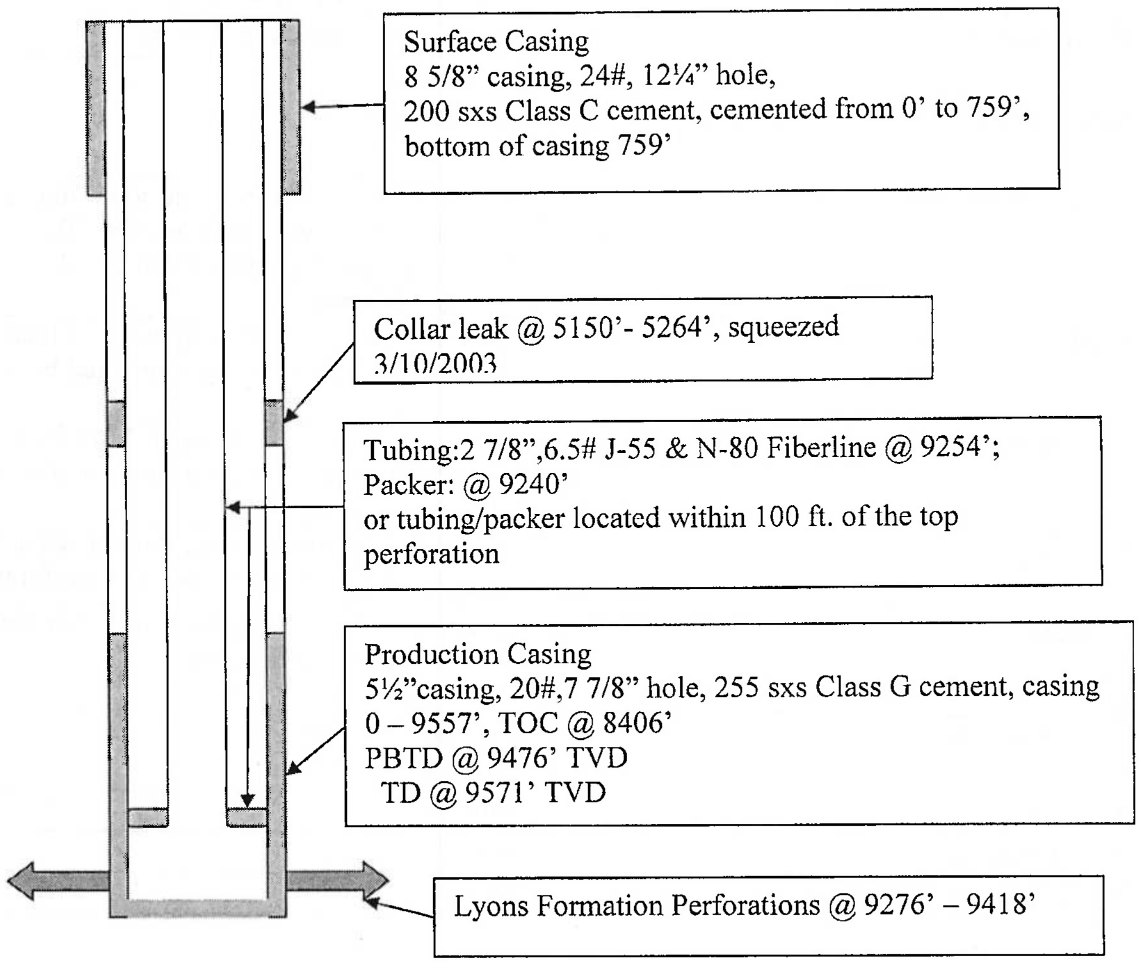
f) Other Information. Where the Permittee becomes aware that he failed to submit any relevant facts in the permit application, or submitted incorrect information in a permit application or in any report to the Director, the Permittee shall submit such facts or information within two (2) weeks of the time such information became known to him.

APPENDIX A CONSTRUCTION PROCEDURE

The construction procedures for the SUCKLA FARMS INJECTION WELL #1, are presented below.

CATEGORY	DESCRIPTION
Well Name	Suckla Farms Injection Well #1
API Number	05-123-14291
Location	SENW, 500 feet (ft) from the south line and 2020 ft from the west line, Section 10, Township 1 North, Range 67 West, Weld County, Colorado
Surface Casing	8 5/8 inch casing, 24 lb weight, 12 ¼ inch hole, 0 – 759 ft. depth of casing, cemented between 0 – 759 ft.
Production Casing	5 ½ inch casing, 20 lb. weight, 7 7/8 inch hole, 0 – 9557 ft. depth of casing, cemented between 8406 ft. – 9557 ft.
Tubing	2 7/8 inch Fiberline tubing, shall be set at 9254 ft. or within 100 ft of the top open perforation
Packer	Packer shall be set at 9240 ft or within 100 ft of the top open perforation
Perforations	9276 ft. – 9418 ft.
Top of Cement	8406 ft.
Total Depth	9571 ft.
Plug Back Total Depth	9476 ft.

Suckla Farms #1 Disposal Well
SENW, 500 feet (ft) from the south line and 2020 ft from the west line, Section 10, Township 1 North, Range 67 West, Weld County, Colorado
API No. 05-123-14291



APPENDIX B MONITORING AND REPORTING

This is a listing of the parameters required to be observed, recorded, and reported. Refer to the permit Part II, Section E, for detailed requirements for observing, recording and reporting these parameters.

OBSERVE CONTINUOUSLY AND RECORD AT LEAST ONCE EVERY THIRTY DAYS	
OBSERVE AND RECORD	Injection pressure (psig)
	Annulus pressure(s) (psig)
	Injection rate (bbl/day)
	Fluid volume injected since the well began injecting (bbls)
	Sources of waste fluids brought to the facility and total volume injected from each source
MONTHLY	
ANALYZE	Injected fluid total dissolved solids (mg/l)
	Injected fluid specific gravity
	Injected fluid pH
QUARTERLY	
REPORT	Each month's minimum, maximum and average injection pressure (psig)
	Each month's minimum, maximum and average annulus pressure (psig)
	Each month's injected volume (bbl)
	Fluid volume injected since the well began injecting (bbl)
	Each month's annulus fluid level
	Written results of annulus injected fluid analysis
	Sources of all fluids injected during the year and the total volume from each source
	Seismic events occurring between two and fifty miles of the permit boundary.

In addition to these items, additional Logging and Testing results may be required periodically. For a list of those items and their due dates, please refer to Appendix D – LOGGING AND TESTING REQUIREMENTS.

APPENDIX C PLUGGING & ABANDONMENT PLAN

The PLUGGING AND ABANDONMENT PLAN incorporated into this Permit is binding on the Permittee. After receiving approval from the Colorado Oil and Gas Conservation Commission, and notifying the appropriate Regional EPA office, the permitted injection well will be plugged and abandoned in accordance with the following PLUGGING AND ABANDONMENT PLAN.

Note: Cemented areas using balanced plugs shall be tagged. Class C or similar type cement shall be used to Plug and Abandon the Suckla Farms #1 Injection Well. Water-based muds, or brines containing a plugging gel, with a density of at least 9.2 lb/gal shall be used during plugging operations, and shall remain between plugs in the well after cement plug placement.

1. Run a Part I (Internal) Mechanical Integrity Test to evaluate casing integrity. If casing has integrity, prior to plugging and abandoning the Suckla Farms #1 disposal well, the retrievable tension type packer will be released and the tubing and packer will be removed from the wellbore.

2. Plug #1: Isolation of the Injection Zone and Upper Confining Zone
   Run back into the wellbore with a tubing string to the bottom of the 5 ½ inch casing and condition the wellbore. Place a 250 foot cement plug from about 9225 ft to 9476 ft, using either Class B type II neat cement or an equivalent Class G cement. Wait sufficient time for plug to set and tag plug with tubing string. Place a Cast Iron Bridge Plug (CIBP) atop of the cement plug. Place a 50 foot plug atop of the CIBP between the depths of 9175 ft to 9225 ft. Note: the CIBP may be replaced with a cement retainer (CR).

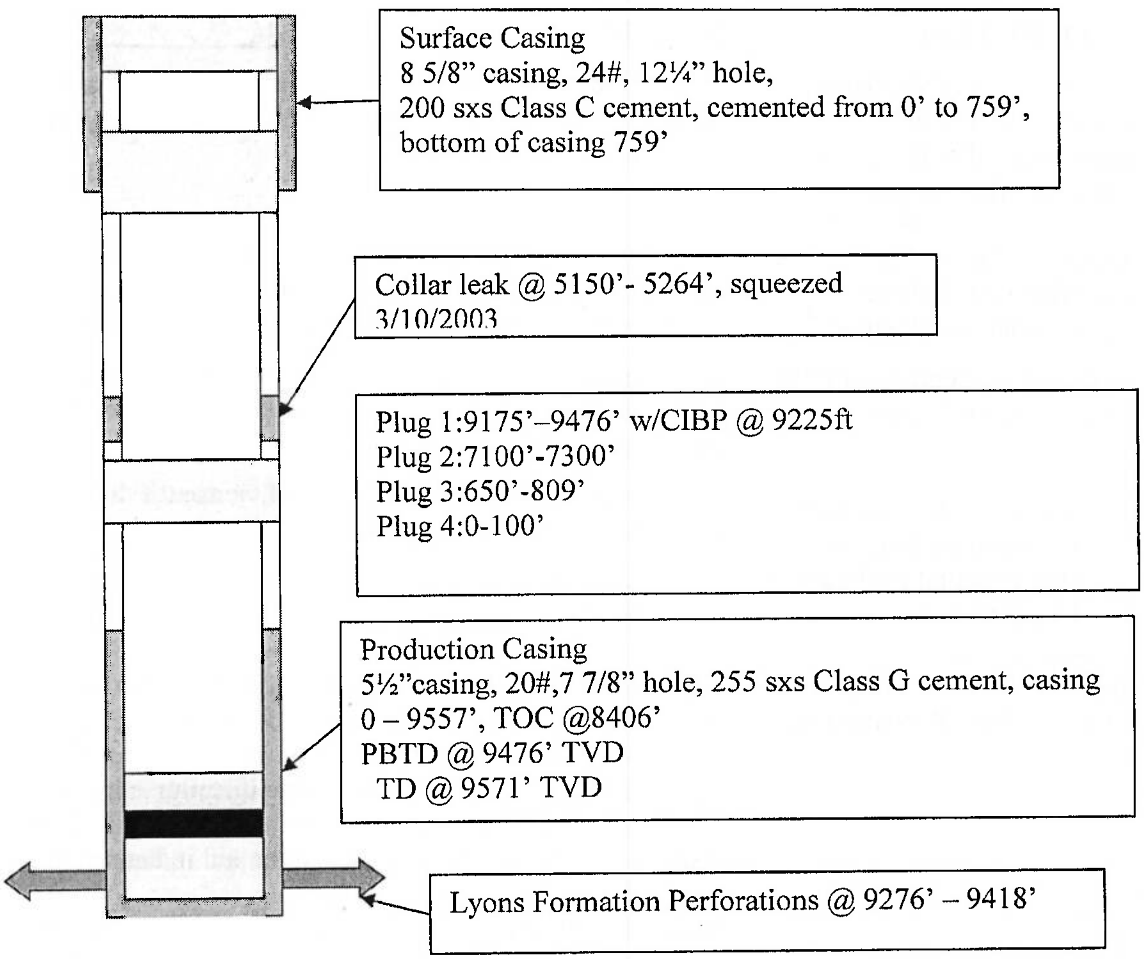
3. Plug #2: Isolation of the Pierre Shale Formation
   Set a 200 ft plug, using Class G, or equivalent type cement, from 7100 ft to 7300 ft inside the 5 ½ inch casing. The 5 ½ inch casing must be perforated and cement squeezed behind pipe between the depths of 7100 ft to 7300 ft.

4. Plug #3: Isolation of Known USDWs and the Casing Shoe
   Within the 8 5/8 inch surface casing and the 7 7/8 inch wellbore, set a 159 foot plug, using Class G or equivalent cement, from 650 ft to 809 ft. The 5 ½ inch casing must be perforated below the casing shoe and cement squeezed into the annular space.

5. Plug #4: Isolation of the Surface
   Within the 8 5/8 inch surface casing, set a sufficient Class "G" cement to fill the casing from the surface to a minimum depth of 100 feet. The 5 ½ inch casing must also be filled with Class "G" cement to a depth of at least100 feet.

6. After the wellbore is plugged the Permit requires cutting off the 8 5/8 inch casing 1 to 3 feet below ground surface. A steel cap dry hole marker is required to be welded on the 8 5/8 inch casing. The surface must then be restored to landowner and/or County requirements.

Suckla Farms #1 Disposal Well
PLUGGING AND ABANDONMENT PLAN
SENW, 500 feet (ft) from the south line and 2020 ft from the west line, Section 10,
Township 1 North, Range 67 West, Weld County, Colorado
API No. 05-123-14291



APPENDIX D LOGGING & TESTING REQUIREMENTS

Tests.
Tests will be conducted according to current UIC guidance. It is the responsibility of the Permittee to obtain and use guidance prior to conducting any well test required as a condition of this permit.

Well Name: SUCKLA FARMS #1 INJECTION WELL

TYPE OF TEST	DATE DUE
Internal (Part I) Mechanical Integrity Test may be demonstrated with a pressure test using fluid or gas.	Shall be performed **at least every five (5) years** after the last successful demonstration of Mechanical Integrity as approved by EPA.
External (Part II) Mechanical Integrity Test shall be demonstrated with either Option 1: A Temperature Log (TL) or Noise Log or Option 2: An Alternate Temperature Log and Supplemental Radioactive Tracer Survey	Shall be performed **at least every five (5) years** after the completion of the last successful Part II External demonstration of Mechanical Integrity as accepted/approved by EPA. If a temperature log (Option 1) only is performed then use the EPA Testing Guideline - "Temperature Logging for Mechanical Integrity," January 12, 1999. The procedure in APPENDIX H shall be used if the Permittee chooses to use the test method for Option 2. Note: All tests must be performed using the maximum allowable injection pressure.
Fall Off Test and Calibration Data and Pore Pressure Data	Shall be performed at least annually (every twelve months) after the last successful demonstration of Pressure Fall Off as accepted/approved by EPA. Shall be performed for the purpose of monitoring pressure buildup in the injection zone in order to detect any significant loss of fluids due to fracturing in the injection and/or confining zone, and to aid in determining the lateral extent of the injection plume.
Cement Bond Logs	Shall be performed after any work over that involves any remedial cementing of the casing, the Permittee shall run a new cement bond log (with a gamma ray, travel time curve, casing locator, amplitude curve, and variable density log) that covers the area of the cementing to verify the adequacy of the cement placement. The bond long shall be run from the surface to the plug back total depth of the well.

APPENDIX E OPERATING REQUIREMENTS

MAXIMUM ALLOWABLE INJECTION PRESSURE:
Maximum Allowable Injection Pressure (MAIP) as measured at the surface shall not exceed the pressure(s) listed below:

Well Name: Suckla Farms #1 Injection Well
Maximum Allowed Injection Pressure: 3700 psi (UIC Compliance/Enforcement Database)
Any increase in pressure that exceeds 3695 psi shall result in an immediate shut down of the injection pumps.

INJECTION ZONE(S):
Injection is permitted only within the approved injection zone listed below. Injection perforations may be altered provided they remain within the approved injection zone and the Permittee provides notice to the Director in accordance with Part II, Section A.6. Specific injection perforations can be found in APPENDIX A.

SUCKLA FARMS #1 INJECTION WELL

FORMATION NAME	**APPROVED INJECTION ZONE, ft**
Lyon	9274 – 9422

FORMATION NAME	**OPEN PERFORATIONS OR HOLE, ft**
Lyon	9276 – 9418

ANNULUS PRESSURE: The annulus pressure shall be maintained at a positive pressure between one hundred (100) and two hundred (200) psi gauge as measured at the wellhead.

Any operation outside of this range shall result in an immediate shut down of the injection pumps. When adjusting the annulus fluid pressure, the Permittee shall use the target value of 150 psi.

If this pressure cannot be maintained between 100 psi and 200 psi, the Permittee shall follow the procedures listed in *Ground Water Section Guidance No. 35* "Procedures to follow when excessive annular pressure is observed on a well."

MAXIMUM INJECTION VOLUME: Cumulative injection volume of oil field water, plus Class I nonhazardous waste fluid will be limited to 8,300,000 barrels over the life of the well unless EPA decides to extend the limits of the injection zone or to terminate the permit.

MAXIMUM INJECTION RATE: The injection rate is not limited.

APPENDIX F CORRECTIVE ACTION

No Corrective Action is required.

APPENDIX G LIST OF APPROVED INJECTION FLUID SOURCES

All injection fluid sources of the Final Permit which became effective on July 21, 1992 (issued on June 16, 1992), sources listed below, and other source fluids previously approved shall be injected into the Suckla Farms #1 well.

SOURCE		DATE OF APPROVAL LETTER
WELL NAME/SOURCES	INJECTION FLUID	
Albert Sack 14-13	Produced Brine	10/25/2006
Barbara Jean 3-31	Produced Brine	10/25/2006
Barnes 2-4	Frac Fluid	10/25/2006
Bernhardt 7-14	Produced Brine	10/25/2006
Bernhardt 7-16	Produced Brine	10/25/2006
Billings	Produced Brine	10/25/2006
Bliss 41-21	Frac Fluid	10/25/2006
Camenisch 32-9	Produced Brine	10/25/2006
Camenisch 32-10	Produced Brine	10/25/2006
Camenisch 32-16	Produced Brine	10/25/2006
Colclasure 42-21	Frac Fluid	10/25/2006
Elaine 43-28	Produced Brine	10/25/2006
Kammerzell 7-4	Produced Brine	10/25/2006
Matsushima 2-6	Produced Brine	10/25/2006
Matsushima 4-19	Produced Brine	10/25/2006
McQueary 2-28	Produced Brine	10/25/2006
Murphy 11-5	Produced Brine	10/25/2006
Rock 7-30	Produced Brine	10/25/2006
Stonebraker 6-12	Produced Brine	10/25/2006
Woolley 42-7	Produced Brine	10/25/2006
Spindle -5128	Produced Brine	2/24/2009
Spindle-5132	Produced Brine	2/24/2009
MEW-21A	Produced Brine	2/24/2009
MEW-21B	Produced Brine	2/24/2009
MEW-4A	Produced Brine	2/24/2009
MEW-23	Produced Brine	2/24/2009
Platt-977/972	Produced Brine	2/24/2009
Platt-975/976	Produced Brine	2/24/2009
Lucerne-17	Produced Brine	2/24/2009
Eaton-3	Produced Brine	2/24/2009
Eaton-1/2	Produced Brine	2/24/2009
Marla-1080	Produced Brine	2/24/2009
Marla-175	Produced Brine	2/24/2009
Ent-1/2	Produced Brine	2/24/2009
Marla-116/117	Produced Brine	2/24/2009
Roggen-1/2	Produced Brine	2/24/2009
PP-5	Produced Brine	2/24/2009
Rein-1362	Produced Brine	2/24/2009
John-3914	Produced Brine	2/24/2009
W-Spindle-S1	Produced Brine	2/24/2009
Marilyn-7	Produced Brine	2/24/2009

Marilyn-6	Produced Brine	2/24/2009
Single-S2	Produced Brine	2/24/2009
Surry-S1	Produced Brine	2/24/2009
Martha-S1	Produced Brine	2/24/2009
Mid-6	Produced Brine	2/24/2009
Jody-6	Produced Brine	2/24/2009
Tampa-2/4	Produced Brine	2/24/2009
Centennial drip leg plant tank 1	Produced Brine	3/17/2010
Angi/Allee receiver plant tank 1	Produced Brine	3/17/2010
Greeley plant tank 1	Produced Brine	3/17/2010
McCarthy #10-21	Produced Brine	4/28/2009
Koester #18-33	Produced Brine	10/31/2011
Stroh #7-33	Produced Brine	2/25/2008
Stroh #15-28	Produced Brine	2/25/2008
Cam #20-32	Produced Brine	2/25/2008
Bernhardt #7-16	Produced Brine	10/16/2008
Camenisch #32-16	Produced Brine	10/16/2008
Hepp 31-32	Produced Brine	9/22/2008
Sunmarke #15-28	Produced Brine	3/7/2008
Billing 21-7	Frac Fluid	2/14/2006
Stroh 33-1	Frac Fluid	2/14/2006
Stroh 33-2	Frac Fluid	2/14/2006
KP Kauffman Oil Field Vehicles	Wash Bay Water	1/17/2006
Storage tanks located in north central Colorado and owned by Koch Oil Company	Wastewater from crude oil storage tanks	12/9/1998
Conoco Spindle "A" Facility near Ft. Lupton, Colorado	Exporation & Production Fluid wastes in tanks	12/8/1998
US Mint, 320 Colfax Avenue, Denver, Colorado	Quenching bath solution (metal cleaning bath mix)	10/26/1998
Lundquist Association Underground Storage	Gasoline and water mix generated from the removal of an Underground Storage Tank (UST)	6/18/1998
Tank at Chase Pipeline Company Terminal in Aurora, Colorado	Wastewater used to hydrotest a newly constructed pipeline	2/23/1998
Weld County Waste Disposal, Inc. Facility	Brine Water	1/28/1998
Copper Mountain Conoco Station	Cleanout fluids from an UST	10/1/1997
Electronics Metal Products, 21000 East 32nd Parkway, Aurora, Colorado	Detergent metal cleaning bath solution	8/28/1997
Tank at B-Line Systems, 21000 E. 32nd Parkway, Aurora, Colorado 80011	Phosphate Waste	6/12/1997
Monitoring wells at F.E. Warren AFB, Cheyenne, Wyoming	Purge Water	5/22/1997

Tank of B-Line Systems, 21000 E. 32nd Parkway, Aurora, Colorado 80011	Water Rinsate used to rinse off soap from steel plates-520 gal	5/19/1997
Tank of B-Line Systems, 21000 E. 32nd Parkway, Aurora, Colorado 80011	Water Rinsate used to rinse off soap from steel plates-6000 gal	5/8/1997
Tank of B-Line Systems, 21000 E. 32nd Parkway, Aurora, Colorado 80011	Water Rinsate used to rinse off soap from steel plates-1000 gal.	4/17/1997
Tank of B-Line Systems, 21000 E. 32nd Parkway, Aurora, Colorado 80011	Phosphate Waste-650 gal.	2/20/1997
Tank of B-Line Systems, 21000 E. 32nd Parkway, Aurora, Colorado 80011	Water Rinsate used to rinse off soap from steel plates- 500 gal.	1/10/1997
Tank of B-Line Systems, 21000 E. 32nd Parkway, Aurora, Colorado 80011	Water Rinsate used to rinse off soap from steel plates-2800 gal.	3/19/1997
Tank at H & H Tooling, 430 South Navajo Street, Denver, Colorado 80223	Water used to heat treat steel-50 gal.	11/26/1996
Solar Heating System, Mr. Barry Baughman at 725 York Street, Denver, Colorado 80206	Water from a solar heating system	11/19/1996
Electronics Metal Products, 21000 East 32nd Parkway, Aurora, Colorado	Detergent metal cleaning bath solution-6400 gal.	11/14/1996
Mohawk Lab Div., NCH Corp., Erving, Texas	Industrial Cleaning Solution	9/27/1996
Pace Incorporated in Golden, Colorado	Waste water from laboratory sample preparation process-5,000 to 7,000 gal.	9/25/1996
Electronics Metal Products, 21000 East 32nd Parkway, Aurora, Colorado	Detergent metal cleaning bath solution-2800 gal.	9/25/1996
Kapp Tech, 2870 Wilderness Place, Boulder, Colorado	Nickel and ethylenediamine tetraacetic acid (EDTA) containing solutions-5000 gal/month	7/24/1996
Glycol Specialties, 705 West 62nd Avenue, Denver, Colorado	Glycol/water mix – 20,000 gal.	5/30/1996
F.E. Warren Air Force Base in Cheyenne, Wyoming	Purge Water-100,000 gal – 130,000 gal.	12/13/1995
UST – AET Environmental, Denver, Colorado	UST Cleanup fluid-2500 gal.	10/11/1995
Highway 36 Landfill,	Leachate from landfill-500,000 to 1,000,000 gal. per year	5/25/1995
Laidlaw building site	Ground water samples	5/16/1995
Other sites and sources identified or to be identified.		

APPENDIX H ALTERNATE TEMPERATURE SURVEY TEST WITH SUPPLEMENTAL RADIOACTIVE TRACER SURVEY PROCEDURE

Mechanical Integrity Testing Procedures
for
Suckla Farms #1 Class I Disposal Well

Wattenberg Disposal, LLC
Denver, Colorado

1.0 Part II External MI (Baseline Temperature Logging)

1. Confirm that well has been shut-in for a minimum of 36 hours. Obtain wastewater flow rate records for most recent injection event.

2. Mobilize wireline unit to well location.

3. Rig up wireline unit and mast and connect pressure lubricator system to well crown. Pick up tool string consisting of temperature and casing collar locator (CCL) tools.

4. Run in well while recording the temperature profile from surface to total depth or plug back total depth at a rate of 20 to 30 feet per minute. (**The initial reading is the baseline temperature log.)** Note water level depth based on temperature log response, and note top of packer depth with CCL and correlate log depth. Tag and record total depth of well.

WELL NAME	PACKER DEPTH, ft	TOTAL DEPTH, ft.	PLUG BACK TOTAL DEPTH, ft.
Suckla Farm #1	9240	9571	9476

5. Pull out of well with temperature tool and lay down. Prepare well and location for radioactive tracer (RAT) survey and repeat temperature logging.

2.0 Part II External MI (Repeat Temperature Logging) with accompanying Radioactive Tracer Survey

Note: All tests performed shall perform all injections at the maximum allowable injection pressure.

1. Pick up RAT survey tool configured with two gamma ray detectors, CCL, and RAT ejector.

2. Assure that any well vacuum has been released. Run in well with RAT tool. Correlate RAT tool depth with packer position from previous temperature log CCL.

3. Tag and record total depth of well, and compare to previous temperature log depth. Pull pre-RAT GR/CCL survey to at least 200 feet above log-indicated packer signature at a speed not to exceed 60 feet/minute.

4. Make 5-minute statistical survey checks at 10 feet above packer (Harriman Confining Zone) and 20 feet above the uppermost well perforations (Lyons Injection Zone).

5. Pick up RAT tool 200 feet above packer and initiate injection at 40 to 50 gallons per minute (gpm) using plant injection pump and effluent, or other rate as needed to properly profile the down-hole progression of the radioactive (RA) material slug depending on the injection tubing diameter.

6. Release RA material slug in tubing and profile slug into injection perforations. Assure that at least two RA peaks are encountered above the perforated interval.

7. Repeat steps 5 and 6.

8. Pick up RAT tool and release RA material slug at maximum allowable injection pressure (MAIP) 20 feet above the top perforation (located at approximately 9276 feet). Log through the RA material slug. Compare the fluid velocity at points above the top perforation and below the bottom perforation for the set of perforations between the depths of 9276 feet to 9418 feet. The depth drive method may be used to log the velocities. Determine the % of fluids entering the set of perforations.

9. Continue to profile the RA material slug below the bottom perforation to the plug back total depth for the well.

10. Position RAT tool 20 feet above the well perforations. Increase the injection rate making sure that the injection rate and pressure do not exceed the permit limits.

11. Release a slug of RA material at MAIP and hold RAT tool stationary while logging in time drive for either 1 hour or by calculating 3t, where t is the time calculated for radioactive fluid inside the casing to flow from the detector tool to the uppermost effective perforation.

12. Verify injection rate. Repeat step 9.

13. Evaluate RAT survey results. Cease injection and run in well to total depth. Pull post-RAT GR/CCL survey to 200 feet above log-indicated packer signature at a speed not to exceed 60 feet/minute.

14. Evaluate post –RAT GR/CCL survey. Dump RAT tool of remaining contents and pull out of well with wireline and logging tools. Lay down RAT tool.

15. Run a dynamic Temperature Log while actively injecting into the well at normal operating conditions (See Section 1.0, as applicable) or at the MAIP.

16. Shut-in well overnight (minimum of eight hours).

17. Pick up temperature logging tool as specified in Section 1.0. Repeat step 4 in Section 1.0.

18. Compare second pass (repeat) temperature log to first pass (baseline) temperature log. If no anomalies are noted and baseline signature is replicated, then pull out of well with temperature tool, and prepare well and location for annulus pressure test (APT).

19. If an anomaly(s) is noted and/or signatures do not repeat a baseline pass, wait 24 hours and run third (repeat) pass with the well shut in from surface to total depth. Log into hole at 20-30 feet/minute. Wattenberg is encouraged to consult with EPA, as needed, to discuss the presence of any anomolies.

20. Repeat Step 17 if third (repeat) pass still shows an anomaly(s), repeat until baseline pass signature is replicated.

3.0 3.0 Part I Internal MI (Annulus Pressure Test)

1. Once all other testing is complete, rig up APT gauge on outlet on well annulus. Review Annulus Pressure Test procedures in US EPA Guidance No. 39.

2. Pressurize well annulus with plant pressurization system to a minimum of 1,000 psi, (recommend using 1,050 psi as the effective test pressure). The annular test pressure must, however, have a difference of at least 200 psig either greater or less than the injection tubing pressure.

3. Isolate well annulus from pressure source and record annulus pressure for at least thirty minutes at a data recording rate of at least once every five minutes (as specified in USEPA Guidance No. 39). However, a more frequent data recording rate of approximately one measurement every 10 seconds is recommended. Record the initial and final tubing pressure observed for this test.

4. Evaluate results. According to USEPA Guidance No. 39, a successful test is one in which the maximum annulus pressure change does not exceed 10% of the initial test pressure. Release test pressure to normal operating range. Re-establish normal annulus pressure monitoring configuration.

5. Rig down wireline unit. Assure that well location is clean and that the well has been restored to a normal configuration. Move to next well site. If all testing is complete at all wells, then release wireline unit.

APPENDIX I SITE SECURITY AND MANIFEST SYSTEM

The Permittee shall maintain the following existing Site Security and Manifest System:

Site Security

Signage
Waterproof sign(s) shall be maintained and readily visible at the entrance from public roads leading to the commercial disposal well. The sign(s) shall indicate the property is private, no trespassing is allowed, and shall include the name of the Permittee and emergency contact phone number.

Gates and Fences
The perimeter of the site shall be fenced with a minimum 6-foot high metal pipe fence with woven wire between the posts or an equivalent chain-linked fence. All gates and other entry points shall be locked when the facility is unattended. Only authorized personnel shall have access to the site and ability to open the gates.

Surveillance
The site shall be monitored by 24 hour camera surveillance (i.e. recording cameras). If an electronic system is used to secure the facility or if fluids to be disposed in the well are transported to the facility by pipe, an automatic shut-off or alarm system is available to ensure that disposal operations cease if a well mechanical failure or downhole problem occurs. If an electronic system is not used to secure the facility, fluids shall be received for placement in a commercial disposal well only when there is an attendant on duty if fluids are hauled in by truck. All sites not protected by an electronic system shall be secured by a locked gate when an attendant is not on duty.

Tamper Proof Locks
The Permittee shall provide tamper-proof seals for the master valve on the well; and install locking caps on all valves and connections on holding tanks, unloading racks, and headers.

Leak containment. A means for containing leaks shall be provided at all pumps and connections.

Manifest System and Chain of Custody for Disposal Water

All sources of fluids must be approved by the EPA prior to disposal.

1. The Permittee shall establish and maintain a three-party custody record between the Generator (responsible party from where the fluids were generated), Transporter, and Disposal Facility (Permittee). For every disposal load received, the following information shall be recorded:

- Generator: company name, company address, company telephone number, the name and location of the lease from where fluids were produced (the Permittee will keep track of all production wells that are contained within each lease approved to use the Disposal Facility)
- Transporter: company name, company address, company telephone number, truck driver name, truck identification number, date of pick up, volume of fluids picked up from the Generator
- Disposal Facility: facility name, facility address, facility telephone number, date and volume of fluids unloaded at the Disposal Facility

These records shall be kept for a minimum of three years after date of disposal at the facility and shall be made available for inspection upon request.

2. The Transporter and Permittee shall certify that no hazardous waste was mixed in with the fluids to be injected into the well.

   The Transporter certification statement shall reads as follows:
   I certify under penalty of law that the waste fluids that I am transporting has not been mixed with hazardous wastes, and I have transported the waste fluids in compliance with Department of Transportation requirements for injection into a well subject to the requirements for the Underground Injection Control Program of the Safe Drinking Water Act.

   The Disposal Facility certification read as follows:
   I certify under penalty of law that the waste fluids that are injected into the Suckla Farms #1 well authorized under Permit No. CO10938-02115 are not hazardous and has not been mixed with, or otherwise co-injected with, hazardous waste at the Underground Injection Control (UIC) Class I permitted facility, and that injection of the waste fluids is in compliance with the applicable requirements contained in this Permit.

3. The Permittee shall submit a report to the Director and to the Generator describing any discrepancies in the composition, transported volumes or place of origin of the injected fluids. These discrepancies may be identified based upon personal observations or information contained on the three-party custody record. This report shall be submitted quarterly to Region 8 UIC Enforcement Program with other required reports.

4. The Permittee shall insure that each source of injected fluid shall be sampled in accordance with the permit conditions under Part II.D.5 and Part II.E.1.

APPENDIX J MONITORING PARAMETER LIST

TOPIC	PARAMETER	UNIT	METHOD
Field Parameters	pH		
	Specific Conductance		
	Temperature		
	TDS	Mg/l	
	Specific Gravity		
	Total Organic Carbon		
Cations	Magnesium	Mg/l	6010B
	Sodium	Mg/l	6010B
	Potassium	Mg/l	6010B
	Calcium	Mg/l	6010B
Anions	Carbonate	Mg/l	SM 2320
	Bicarbonate	Mg/l	SM 2320
	Chloride	Mg/l	325.3
	Sulfate	Mg/l	375.4
	Nitrite (as N)	Mg/l	353.2
	Nitrate (as N)	Mg/l	353.2
Metals	Antimony	Mg/l	200.8, 200.9
	Aluminum	Mg/l	
**use total metals and not dissolved Metals*	Arsenic	Mg/l	200.7, 200.8, 200.9
	Barium	Mg/l	200.7, 200.8
	Beryllium	Mg/l	200.7, 200.8, 200.9
	Boron	Mg/l	200.7, 212.3
	Cadmium	Mg/l	200.7, 200.8, 200.9
	Chromium (total)	Mg/l	200.7, 200.8, 200.9
	Copper	Mg/l	200.7, 200.8, 200.9
	Cyanide	Mg/l	335.4
	Flouride	Mg/l	300
	Iron (total)	Mg/l	200.7, 200.8
	Lead	Mg/l	200.8, 200.9
	Mercury (inorganic)	Mg/l	200.8, 245.1, 245.2
	Manganese	Mg/l	200.7, 200.8, 200.9
	Molybdenum	Mg/l	200.7, 246.1, 246.2
	Nickel	Mg/l	200.7, 200.8, 200.9
	Selenium	Mg/l	200.8, 200.9
	Silver	Mg/l	200.7, 200.8, 200.9
	Strontium	Mg/l	200.7, 272.1, 272.2
	Thallium	Mg/l	200.8, 200.9

	Zinc	Mg/l	200.7, 200.8
Organics	Total Organic Carbon (TOC)	Mg/l	9060
	Total Recoverable Petroleum Hydrocarbons (TRPH)	Mg/l	418.1
	Benzene	Mg/l	8021B
	Toluene	Mg/l	8021B
	Ethylbenzene	Mg/l	8021B
	Xylenes, total	Mg/l	8021B
	Vinyl Chloride		
	1,2 Di-chloroethane		601, 624 or 1624B
	Ethylene Dibromide		
Biological	Total Coliform		
	Turbidity		180.1
Radiological	Uranium	Mg/l	908.0, 908.1
	Radium - 226	pCI/L	304
	Radium - 228	pCI/L	304
	Gross Alpha	pCI/L	E900.0
	Gross Beta	pCI/L	E900.0
All applicable EPA regulations	All applicable tables in Table I of 40 CFR Section 136.3		
	Appendix III of 40 CFR Part 261		
Other Constituents as needed			